LSU / MMS WELL CONTROL WORKSHOP

May 23-24, 1995

8HHH

LSU/MMS WELL CONTROL WORKSHOP

Registration

8:00-8:30 am., TUESDAY, MAY 23, IN ABELL BOARD OF DIRECTORS ROOM,
LOD COOK ALUMNI CENTER, 3838 W. LAKESHORE DRIVE
BATON ROUGE, LA

Shallow-Gas Flows while Waiting on Cement

TUESDAY MORNING – SESSION 1, ABELL BOARD OF DIRECTORS ROOM

8:30 am. 1. INTRODUCTION AND WELCOME
Adam T. Bourgoyne, Jr., LSU

8:45 am. 2. OBJECTIVES AND SCOPE OF MEETING
James Regg, MMS

9:00 am. 3. REVIEW OF 15 KNOWN SHALLOW GAS INCIDENTS
Lee Fowler, MMS

9:45 am. 4. CURRENT REGULATORY REQUIREMENTS
James Regg, MMS

10:15 am. Coffee Break
Courtesy of Diamond Offshore Drilling, Inc.

10:35 am. 5. DISCUSSION OF TECHNICAL CONSIDERATIONS
- A. Set-up Time
- B. Compressive Strength
  - 1. Minimum necessary to prevent cement migration
  - 2. Measurement procedures (laboratory vs. field)
- C. Other relevant properties (Gel, Fluid loss, Compressibility, etc.)
- D. Technology (tools, procedures, composition, etc.)

11:45 am. LUNCH (Courtesy of Wild Well Control, Inc.)
Willis Noland and John Laborde Hall
LOD COOK ALUMNI CENTER

TUESDAY AFTERNOON – SESSION 2, ABELL BOARD OF DIRECTORS ROOM

1:00 pm. 6. CONTINGENCY PLANNING FOR WELL CONTROL OPERATIONS
Pat Campbell, Wild Well Control, Inc.

1:45 pm. 7. INDUSTRY INPUT AND OPERATIONAL CONSIDERATIONS
- A. Criteria for WOC
- B. Washing out annulus
- C. Contingency Plan (Shut-in, Divert, Bull-head, etc)
- D. Inclusion in Application to Drill
- E. Other recommendations

2:30 pm. Coffee Break

2:50 pm. 8. RELATED RESEARCH AT LSU
Adam T. Bourgoyne, Jr., LSU

3:10 pm. 9. FOLLOW-UP DISCUSSION
James Regg, MMS

4:00 pm. 10. SUMMARY AND CONCLUSIONS
James Regg, MMS

Tour of Research Well Facility

6:00 pm. BARBECUE (Courtesy of SWACO Geolograph)
AND SITE VISIT
2829 Gourrier Road
BLOWOUT PREVENTION RESEARCH WELL FACILITY

Well Control Research Project Review

WEDNESDAY MORNING – SESSION 3, ABELL BOARD OF DIRECTORS ROOM

8:00 am. 11. OVERVIEW OF LSU RESEARCH PROGRAM ON WELL CONTROL
Adam T. Bourgoyne, Jr.,LSU

8:30 am. Workshop Discussion

8:45 am. 12. IMPROVED COMPUTER MODEL FOR PLANNING DYNAMIC KILL OF UNDERGROUND BLOWOUTS
Alvaro Negrao, Petrobras

9:15 am. Workshop Discussion

9:30 am. 13. GAS KICK BEHAVIOR DURING BULLHEADING OPERATIONS
Richard Duncan, LSU

10:00 am. Workshop Discussion

10:15 am. Coffee Break

10:30 am. 14. EXPERIMENTAL STUDY OF EROSION RESISTANT MATERIALS
Alok Jain, LSU

11:00 am. Workshop Discussion

11:15 am. 15. USE OF SOIL BORINGS DATA FOR ESTIMATING BREAKDOWN PRESSURE OF UPPER MARINE SEDIMENTS
Catherine V. Bender, LSU

11:45 am. Workshop Discussion

11:55 am. LUNCH (Courtesy of Halliburton Energy Services)
Willis Noland and John Laborde Hall
LOD COOK ALUMNI CENTER

"API TASK GROUP ON DRILLSTRING SAFETY VALVES"
Adam T. Bourgoyne, Jr., LSU

WEDNESDAY AFTERNOON – SESSION 4, ABELL BOARD OF DIRECTORS ROOM

1:00 pm. 16. WELL DESIGN REQUIREMENTS TO REDUCE THE VUNERABILITY OF MARINE STRUCTURES TO CRATERING
Darryl A. Bourgoyne, LSU

1:30 pm. Workshop Discussion

1:45 pm. 17. RECONFIGURATION OF LSU NO. 1 TEST WELL
O. Allen Kelly, LSU

2:15 pm. Workshop Discussion

2:30 pm. Coffee Break

3:00 pm. 18. CONTROL OF ENVIRONMENTAL RISKS OF AGING OFFSHORE PIPELINES -PROPOSAL FOR SURVEY AND ASSESSMENT OF AVAILABLE TECHNOLOGY
Andrew Wojtanowicz, LSU

3:30 pm. Workshop Discussion

3:45 pm. 19. DEVELOPMENT OF IMPROVED KICK TOLERANCE MODEL FOR DEEPWATER DRILLING OPERATIONS
Shiniti Ohara, LSU

4:15 pm. 20. OPEN FORUM FOR INDUSTRY AND MMS INPUT
Adam T. Bourgoyne, Jr., LSU

4:30 pm. 21. SUMMARY AND CONCLUSIONS
Adam T. Bourgoyne, Jr., LSU and Joe Attard, MMS

Introduction

by Adam T. Bourgoyne, Jr., LSU

The first day of the workshop will be conducted by The Regional Operations Technical Assessment Committee (ROTAC) of the Minerals Management Service. The objective of this portion of the workshop will be to determine possible solutions to well control problems caused by influx of formation fluids into the cement column while waiting on cement to set. Several accidents have resulted on the Outer Continental Shelf (OCS) from gas entering the cement column before the cement has set. In all known events, the diverter system was at least partially nippled-down when the flow was observed at the surface. An informal poll of some operators in the Gulf of Mexico (GOM) indicated a broad range of criteria is being used to determine the length of the waiting period before starting to nipple-down the diverter / blowout preventer.

The second day of the workshop will be a review of ongoing research on well control supported by The Minerals Management Service and by the Oil and Gas Industry. The overall goal of the LSU/MMS research program is to foster technology improvements and safety in the development of new oil and gas reserves from the U. S. Outer Continental Shelf and the 200-mile Exclusive Economic Zone while minimizing the risk to the marine environment and minimizing the waste of our natural resources. The research program has been sponsored under multi-year plans and funded on an annual basis. We are currently approaching the end of the first year of a five-year effort focused on underground blowouts in a marine environment. The goals of this portion of the workshop are to:

- Disseminate information about the results of LSU's well control research projects that have been accomplished during the past year,
- Evaluate the completed research tasks and proposed future research,
- Suggest areas of need not currently being addressed, and
- Develop a priority list for the most needed work that should be undertaken during the next academic year.

Workshop participants include MMS representatives from the various OCS regions and from MMS headquarters, industry representatives, and members of the LSU well control research team. Forms are provided to assist the MMS and industry representatives in recording their evaluation and suggestions on the various topics presented.

The first day of the workshop will start with presentations from ROTAC members that review recent problems and case histories. This will be followed by a discussion of the best available technology for reducing the occurrence of these problems. Experts from all of the major companies offering cementing services have been invited to participate in the technical discussions. Pat Campbell of Wild Well Control, Inc. will address recent developments in contingency planning for well control operations. Time will be provided for industry input and suggested criteria for waiting-on-cement prior to nippling down the diverter / blowout preventers. Operational considerations and the possible need for additional research will also be discussed. The activities of the day will end with a Barbecue sponsored by SWACO and a site visit at the LSU Research & Training Well Facility.

The second day of the workshop will start with presentations from LSU's well control research team that will summarize on-going research efforts and our proposed research theme for the next four years. Projects that are currently being proposed for next year will also be presented. At the end of the presentations, an open session will be held to allow participants to evaluate the proposed research plan, to offer ideas and recommendations, and to help assign priorities to possible future work. As was suggested by the participants of the 1994 Workshop, additional time will be allocated for these discussion periods. A short presentation at the Luncheon will bring the participants up-to-date on the plans and activities of a recently formed API Task Group on Drillstring Safety Valves led by Brian Tarr of Mobil Oil. The last session will end with an open forum discussion on future research. The meeting will conclude by 4:45 pm.

Preregistered Workshop Participants (5/17/95)

	Attending Day 1	&/or Day 2
MMS Headquarters		
1. William (Bill) Hauser, Petroleum Engineer Minerals Management Service Mail Stop 4700, 381 Eden St. Herndon, VA 22070	X	X
MMS Pacific OCS Region		
2. Michael Lee, Petroleum Engineer Minerals Management Service Paseo Camarillo Camarillo, CA 93010 Phone (805) 389-7570, Fax (805) 389-7592	X	X
3. Nabil Masri, Supervisory Petroleum Engineer Minerals Management Service Paseo Camarillo Camarillo, CA 93010 Phone (805) 389-7581, Fax (805) 389-7592	X	X
4. Philip R. Schroeder, District Supervisor Minerals Management Service 222 W. Carmen Dr., Suite #201 Santa Maria, CA 93454 Phone (805) 922-7958, FAX (805) 925-8546	X	X
5. Khaleeq Siddiqui, Petroleum Engineer Minerals Management Service 770 Paseo Camarillo Camarillo, CA 93010 Phone (805) 389-7775, Fax (805) 389-7784	X	X
MMS Gulf Coast Region		
6. James Behrens, Petroleum Engineer Minerals Management Service 115 Circle Way Lake Jackson, TX 77566 Phone (409) 299-1041, FAX (409) 299-1928	X	X
7. Lee Fowler, Petroleum Engineer Minerals Management Service 1201 Elmwood Park Boulevard New Orleans, LA 70123 Phone 504 736 2924	X	X

Preregistered Workshop Participants (5/17/95)

	Attending **Day 1** &/or	**Day 2**
8. Joe Gordon, Petroleum Engineer Minerals Management Service 825 Kaliste Saloom Road Brandywine II, Suite 201 Lafayette, LA 70508	X	X
9. Lars Herbst, Drilling Engineer Minerals Management Service 1201 Elmwood Park Boulevard New Orleans, LA 70123 Phone (504) 736 2504, Fax (504) 736 2836	X	X
10. B. J. Kruse, Petroleum Engineer Minerals Management Service 1201 Elmwood Park Boulevard New Orleans, LA 70123	X	X
11. Doug McIntosh, Petroleum Engineer Minerals Management Service 1201 Elmwood Park Boulevard New Orleans, LA 70123	X	X
12. William H. Martin, Petroleum Engineer Minerals Management Service 1201 Elmwood Park Blvd. New Orleans, LA 70123 Phone (504) 736-2534, FAX (504) 736-2426	X	X
13. James Regg, Petroleum Engineer Minerals Management Service 1201 Elmwood Park Boulevard New Orleans, LA 70123 Phone (504) 736 2843, Fax (504) 736 2426	X	X
14. Ed Smith, District Supervisor Minerals Management Service 115 Circle Way Lake Jackson, TX 77566 Phone (409) 299-1041, Fax (409) 299-1928	X	X

Preregistered Workshop Participants (5/17/95)

	Attending Day 1	&/or Day 2

Industry Participants

Participant	Day 1	Day 2
15. David Alwell, Regional Drilling Manager Kerr-McGee Corporation P.O. Box 39400 Lafayette, LA 70503		
16. Randy Bayne, Staff Drilling Engineer Columbia Gas Development Corporation P. O. Box 1350 Houston, TX 77251-1350 Phone (713) 871 3311, Fax (713) 871 3578	X	-
17. Dennis Black Unocal - North America Oil & Gas Division 14141 Southwest Freeway Sugarland, TX 77478 Phone (713) 287 7545	X	X
18. Pat Campbell Wild Well Control 22730 Gosling Rd Spring, TX 77389 Phone (713) 353 5481, Fax (713) 353 5480	X	-
19. Marc Duncan, Senior Drilling Engineer Enserch Exploration 4849 Greenville Ave. Dallas, TX 75206 Phone (214) 987-6493, FAX (214) 987-7711	X	-
20. Darryl Etherington, International Sales Williams Tool Company, Inc. P. O. Box 6155 Fort Smith, AR 72906 Phone (501) 646 8866, Fax (501) 646 3502	X	X
21. Ronald Faul, Technical Specialist Halliburton 1450 Poydras Suite 2070 New Orleans, LA 70112	X	-

Phone (504) 593 6700, Fax (504) 593 6725

Preregistered Workshop Participants (5/17/95)

	Participant	Attending Day 1	&/or Day 2
22.	William Flores, Jr., Vice President for Operations Flores & Rucks, Inc. 500 Dover Blvd., Suite 300 Lafayette, LA 70503 Phone (318) 989 5900, Fax (318) 989 5959	X	-
23.	Craig Gardner, Senior Cement Specialist Chevron 2202 Oil Center Court Houston, TX 77073 Phone (713) 230-2676, FAX (713) 230-2740	X	-
24.	Riley Goldsmith, Drilling Engineer Pennzoil Exploration and Production P. O. Box 2967 Houston, TX 77252 Phone (713) 546 8389	-	X
25.	James Hebert, Operations Manager Diamond Offshore P. O. Box 4558 Houston, TX. 77094 Phone, 713 647 2246, Fax 713 647 2216	X	X
26.	Harry Howard, Staff Engineer Murphy Exploration & Production P. O. Box 61780 New Orleans, LA 70161 Phone 504 561 2977, Fax 504 561 2667	X	-
27.	Al Hermann, Senior Technical Advisor Exxon USA P.O. Box 61707 New Orleans, LA 70161-1707 Phone 504 561 4785, Fax 504 561 4416	X	-
28.	Geoffery Kimbrough, Senior Drilling Engineer Diamond Offshore 15415 Katy Freeway Houston, TX 77094 Phone 713 647 2232, Fax 713 647 2158	X	-

Preregistered Workshop Participants (5/17/95)

	Attending Day 1	&/or Day 2
29. Larry Moran, Staff Engineer Conoco, Inc. P.O. Box 2197 Houston, TX 77252-2197 Phone (713) 293-1244, Fax (713) 293-3424	X	-
30. George Murphy, Sales Representative SWACO 361 Ambassador Caffery, Suite 100 Lafayette, LA 70503 Phone (318) 984-6466, FAX (318) 984-0685	X	-
31. Alvero Negrao, Drilling Engineer Petrobras Av. Rep. do Chile 65 sala 2008 Rio de Janeiro, Brazil	X	-
32. Chris Nelson, Prof. Drilling Engineer Amerada Hess P. O. Box 2040 Houston, TX 77252-2040 Phone (713) 609 5989	X	X
33. Tom Neurauter Neurauter & Associates 3311 Dobbin Stream Lane Houston, TX 77084 Phone (713) 578-8760	X	-
34. Don Shackelford, Technical Specialist Halliburton Well Control P. O. Drawer 1431 Duncan, OK 73536-0950 Phone (405) 251-4630, FAX (405) 251 4406	X	X
35. Norm Smith, Drilling & Production Coordinator Columbia Gas Development Corporation P. O. Box 1350 Houston, TX 77251-1350 Phone (713) 871 3400, Fax (713) 871 3485	X	-

Preregistered Workshop Participants (5/17/95) Attending **Day 1** &/or **Day 2**

		Day 1	Day 2
36.	David Stiles, Area Engineer Dowell 639 Loyola Suite 1850 New Orleans, LA 70113 Phone (504) 581 1771, Fax (504) 581 4176	X	X
37.	John R. Swinson Chevron Petroleum Technology Company 2202 Oil Center Court Houston, TX 77073 Phone (713) 230 2628, Fax (713) 230 2768	X	X
38.	Ted Triche, Training Diamond Offshore Drilling, Inc. P. O. Box 4558 Houston, TX 77210 Phone (713) 492-5300, FAX (713) 492-5316	X	X
39.	Curtis Weddle, Global Drilling Consultant BP Exploration P. O. Box 4587 Houston, TX 77210-4587 Phone (713) 560 6370, Fax (713) 560 8859	X	X
40.	Jim West, Training Coordinator PETEX, University of TX at Austin 2700 W. W. Thorne Dr. Houston, TX 77073 Phone (713) 443-7144, FAX (713) 443-8722	X	-
41.	Bill Whitney, Engineering Advisor MEPTEC Drilling P. O. Box 650232 Dallas, TX 75265-0232 Phone (214) 951-3685, FAX (214) 951-2512	X	X
42.	Shelby White, Senior Operations Engineer Flores & Rucks, Inc. 500 Dover Blvd., Suite 300 Lafayette, LA 70503 Phone (318) 989-5900, FAX (318) 989-5959	X	X

Preregistered Workshop Participants (5/17/95)

	Attending Day 1	&/or Day 2
43. John Works, Senior Staff Petroleum Engineer Dalen Resources 6688 N. Central Expressway Dallas, TX 75206 Phone (214) 750-3157, Fax 214 750 3845	X	-
44. Richard Vaclavik, Technical Manager Halliburton 1450 Poydras Suite 2070 New Orleans, LA 70112 Phone (504) 593 6788, Fax (504) 593 6822	X	-
45. Jerry L. Winchester, Manager Well Control Services Groups Halliburton Energy Services 712 East Highway 7 P O. Drawer 1431 Duncan, OK 73536-0382 Phone (405) 251-2129, FAX (405) 251-4406	X	-
-- Kerry Cambell Fugro-McClelland Marine Geosciences, Inc. 6100 Hillcroft Houston, TX. 77081	-	-

Cancelled -- Mail copy of proceedings LSU Research Team

	Attending Day 1	&/or Day 2
46. Dr. Zaki Bassiouni, Chairman Petroleum Engineering Department Louisiana State University Baton Rouge, LA 70803-6417 Phone (504) 388-6040, FAX (504) 388-6039	X	X
47. Catherine V. Bender Petroleum Engineering Department Louisiana State University Baton Rouge, LA 70803-6417	X	X

Preregistered Workshop Participants (5/17/95)

Participant	Attending Day 1	&/or Day 2
48. Adam T. Bourgoyne, Jr., Campanile Professor Petroleum Engineering Department Louisiana State University Baton Rouge, LA 70803-6417 Phone (504) 388 6042, Fax (504) 388 6039	X	X
49. Darryl Bourgoyne, Research Associate Petroleum Engineering Department Baton Rouge, LA 70803-6417 Phone (504) 388 8458, Fax (504) 388 8433	X	X
50. Richard Duncan, Research Associate Petroleum Engineering Research and Technology Transfer Laboratory 2829 Gourrier Lane Baton Rouge, LA 70820 Phone (504) 388 8458, Fax (504) 388 8433	X	X
51. Alok Jain, M.S. Candidate Petroleum Engineering Department Louisiana State University Baton Rouge, LA 70803-6417 Phone (504) 388 5215, Fax (504) 388 6039	X	X
52. Allen Kelly, Director Petroleum Engineering Research and Technology Transfer Laboratory 2829 Gourrier Lane Baton Rouge, LA 70820 Phone (504) 388 8458, Fax (504) 388 8433	X	X
53. Shiniti O'hara, Ph. D. Candidate Petroleum Engineering Department Louisiana State University Baton Rouge, LA 70803-6417 Phone (504) 388 8458, Fax (504) 388 8433	X	X
54. John Smith, Ph. D. Candidate Petroleum Engineering Department Louisiana State University Baton Rouge, LA 70803-6417 Phone (504) 388 5215, Fax (504) 388 6039	X	X

Workshop Evaluation Form, Day 1

Session	Evaluation of Workshop Activity				
	Excellent	Good	OK	Poor	Comments
Review of 15 Known Shallow Gas Incidents					
Current Regulatory Requirements					
Technical Discussion of Fluid Migration after Cementing					
Contingency Planning for Well Control Operations					
Discussion of WOC Criteria					
Discussion of Operational Considerations					
LSU Project on Contingency Plans for Handling Flow after Cementing Surface Casing					
Overall Day 1 Workshop on Shallow Gas Migration after Cementing					
Site Visit to Research Facility					

General Comments and Suggestions:

Workshop Evaluation Form, Day 2

Session	Evaluation of Session				Comments
	Excellent	Good	OK	Not Needed	
Research Program Overview					
Improved Computer Model for Planning Dynamic Kill of Underground Blowouts					
Experimental Study of Bull-Heading Operations					
Experimental Study of Erosion Resistant Materials					
Use of Soil Borings Data for estimating Breakdown Pressure of Upper Marine Sediments					
API Task Group on Drillstring Safety Valves					
Well Design Requirements to Reduce the Vulnerability of Marine Structures to Cratering					
Reconfiguration of LSU No. 1 Test Well					
Control of Environmental Risks of Aging Offshore Pipelines - Proposal for Survey and Assessment of Available Technology					
Overall Program					

General Comments and Suggestions:

Suggested Top Research Priorities:

Please indicate your category below

- ☐ MMS Headquarters Representative
- ☐ MMS Pacific Region Representative
- ☐ MMS Gulf Coast Region Representative
- ☐ Research Industrial Sponsor
- ☐ Industry Representative

Shallow Gas Flows While Waiting on Cement

May 23, 1995

Gulf of Mexico OCS Region
Regional Operations Technology Assessment Committee (ROTAC) Workshop

MMS

Agenda

- MMS presentations to focus the discussion
- Key presentations by industry
  - Technical considerations
  - Operational considerations
- Information exchange
- Related work at LSU
- Key issues:
  - solutions to problems (re: shallow gas flow while WOC)
  - criteria for establishing WOC

MMS

ROTAC

- Regional Operations Technology Assessment Committee
  - Gulf of Mexico, Alaska, Pacific ROTACs
  - similar committee in Headquarters
- Review technology advancements affecting MMS regulatory mission (offshore operations)
- Identify operational needs
- Review and prioritize research proposals for inclusion in MMS funding
- Emphasis on operational issues/workshops
  - e.g., *Shallow Gas Flows While Waiting on Cement*

MMS

Workshop Objectives

- Summarize several shallow gas incidents
- Highlight current MMS regulations relating to waiting on cement
- Discuss the MMS Safety Alerts
- Identify current state of anti-gas migration technology and research
- Open discussion on possible solutions to well-control problems caused by shallow gas flows while waiting on cement
- Improve safety

MMS

ROTAC Workshop
Shallow Gas Flows While Waiting on Cement
LSU Lod Cook Alumni Center
May 23, 1995

Background

Several accidents have resulted on the Outer Continental Shelf (OCS) from shallow gas flows occurring while personnel waited for annular cement to develop sufficient compressive strength. The recent known incidents have been documented in Minerals Management Service (MMS) Safety Alert No. 165. In all events, the diverter system was at least partly nippled down before the cement had developed sufficient compressive strength. This is perhaps one of the most critical phases of drilling the well, and potentially the most dangerous. Current MMS regulations tie the wait-on-cement time only to a specific waiting period before drilling is resumed. An analysis of the accidents and associated events leading up to the accidents points to a critical flaw in the MMS regulations regarding waiting-on-cement criteria.

An informal poll of some operators in the Gulf of Mexico (GOM) revealed that there is a broad range of criteria being used for decisions regarding when to nipple down the diverter/blowout preventer, none of which appears to be based on the physical properties of the annular cement.

The MMS GOM OCS Region is convening this workshop as an extension of the Regional Operations Technology Assessment Committee (ROTAC) to discuss the issue of waiting-on-cement criteria. Options for addressing the MMS safety concerns will be openly discussed with the industry, including the merits and disadvantages of each.

SCHEDULE

I. Introduction and Welcome

II. Scope and Intent of Meeting
Appraise industry of problem
Receive industry inputs for solution

III. Review of 15 Known Shallow Gas Incidents

IV. Current Regulatory Requirements

A. Waiting on Cement (WOC) prior to drill out
B. WOC prior to nipple down diverters (no regulation; currently guided by operator policy)

V. Discussion of Technical Considerations

A. Set-up time
B. Compressive strength
1. Minimum necessary to prevent shallow gas migration
2. Measurement procedures
3. Field vs. laboratory measurements
C. Other relevant properties
Gel Strength, Fluid Loss Rate, Slurry Compressibility, Flow Type
D. Technology (tools, procedures, types of cement, etc.)

VI. INDUSTRY INPUTS: Criteria for WOC

A. Time to WOC prior to drill out--how determined/specified
B. Time to WOC prior to nipple down--how determined/specified

VII. Operational Considerations

A. Washing out annulus
B. Inclusion in Application to Drill of procedures to be followed if shallow gas kick occurs while WOC - shut in vs. divert - other procedures
C. Other recommendations

VIII. Follow-up

A. Is research needed? What areas?
B. Investigate practical criteria for WOC
1. Cement properties vs. time
2. Lab vs. field properties

IX. Summary and Conclusion

MMS
GULF OF MEXICO OCS REGION
U.S. DEPARTMENT OF THE INTERIOR/MINERALS MANAGEMENT SERVICE

SAFETY ALERT

No. 165
April 3, 1995

Shallow Gas Flows While Cementing Surface Casing

A well recently blew out while waiting on cement after surface casing was set. After the wiper plug was bumped, the casing was pressure-tested and sugar water was spotted on top of the mud line hanger. The well was static for four hours, and the operator commenced to nipple down the diverter system. Two hours later, the well started flowing gas and cement out the open diverter. The diverter was closed, and the loosened bolts that attach the diverter to the conductor casinghead were reinstalled. Efforts were unsuccessful to stem the flow by pumping saltwater through the conductor casing valve while allowing the well to unload out both 10-inch diverter lines. Approximately one-half hour after the well started unloading, flow began coming from the annulus between the drive pipe and the conductor, and the rig was evacuated.

Several unsuccessful attempts were made to control the flow. Six days after the flow began, the flow rate decreased and the rig was able to move off location. Four days later, the drive pipe, conductor, and surface casings fell to the seafloor and the flow ceased. The next day, a subsea inspection by a remote operated vehicle (ROV) revealed a 25-foot crater at the base of the drive pipe with no bubbles or flow observed. Five months later, another rig moved on location and successfully completed abandonment of the well. There were no injuries or fatalities as a result of this blowout.

A similar incident occurred in July 1994 while spotting water mixed with lignosulfonate (ligno water) after washing the annulus through wash ports on the mud line hanger. After the 20-inch surface casing was cemented, the annulus was washed by circulating through ports on the mud line hanger, and ligno water was spotted. After a gyro survey was run, a diverter line was opened to check for flow. Flow was noticed on the annulus and the diverter line was closed. The annulus pressure was alternately bled off and allowed to build up during the next day. During the next two days, unsuccessful attempts were made to place heavy mud into the annulus by injection and by circulating through the mud line hanger. The well was finally killed by placing 3/4-inch tubing into the annulus and circulating heavy mud. Operations were resumed some three days after the flow began. There were no injuries or fatalities associated with this incident.

In another, less serious incident, a shallow gas flow also occurred after the surface casing was cemented. Nippling down of the diverter was begun seven hours after the plug was bumped and the float valves were checked. The diverter and diverter lines were rapidly reinstalled when flow first began. The well was shut in with a surface pressure of 50 psi, and was killed by lubricating mud into the annulus between the conductor and the surface casings. The annulus was then successfully grouted, and normal drilling operations were resumed 5 3/4 days after the flow first began. There were no injuries or fatalities as a result of this incident.

In still another incident, nipple down of the diverter system and installation of the casing slips were completed two hours after the plug on the surface casing was bumped. A slight gas flow was ignited by a welder making a rough cut on the surface casing one-half hour later. The gas was flowing from a casing valve that was open so that the annulus could be monitored. The flame was extinguished with no damage or injuries when the casing valve was closed. However, when the valve was later reopened, mud and gas flowed from the well. The valve was closed and the diverter was reinstalled on the wellhead. At this point, the seal on the casing slips failed, and 15-20 bbls of mud and gas were discharged through the diverter line. When fluid slowed to a very small stream, a line was connected to the casing valve, and 3 3/4 bbls of mud was pumped between the 13 3/8-inch and 20-inch casings. The well was monitored for 16 hours and 6.9 bbls of mud were recovered. Final flow rate was 2 1/2 gallons per hour, and at this point, the crew prepared to resume normal operations. The lead cement had thixotropic properties typical of slurries used for this application.

All four cases were caused by formation fluids migrating into the annulus as the cement went through a transition before compressive strength was developed. Sixteen similar well-control incidents have been reported since 1973.

The best way to avoid these problems is to select, on the basis of the shallow hazards survey, a surface location that is not directly above a seismically visible shallow gas accumulation. However, if well objectives require drilling from a location in a shallow gas area, or if it is likely that gas sands will be penetrated in the surface hole, appropriate consideration as to how to handle any shallow gas related problem that might arise should be developed when the well is planned. This consideration is particularly important where the hydrostatic head is to be reduced by activities such as washing mud or cement from the upper annulus with water to facilitate future abandonment.

Items to be considered in shallow gas areas may include the following:

1. Improving cement properties to minimize chances of shallow gas flow, including density, fluid loss, transition time, compressibility, etc.

2. Planning for optimum cement column length (within guidelines established in 30 CFR 250.54)

3. It may be desirable to hold slight back pressure on the annulus after cement is in place, and to consider shut-in of the well rather than diverting the well. In these cases, leakoff testing of the conductor casing shoe is recommended to better predict the surface pressures that could later be withstood without fracturing. Based on results of the leakoff test, the amount of back pressure that could safely be applied until cement has achieved compressive strength should be calculated. Any applied back pressure should not be enough to cause the formation at the conductor shoe to break down, and the annulus should be bled as required to avoid breakdown.

The considerations made regarding shallow gas should also seriously address whether or not the parameters associated with a particular well suggest diversion after cement is in place as a viable option. These parameters include leakoff test data and various depths at which gas sands may be drilled in the surface hole. The mindset that "diversion is the best option because a diverter system is in place" may need to be reexamined. In many cases, the planned shut in of a well may provide for a safer means of well control than diverting the well, especially after cement is in place.

Current regulations require waiting on cement for 12 hours before drilling out all casing strings other than the conductor casing, and that cement have a minimum of 500-psi compressive strength in the bottom 500 feet. This waiting time does not specifically apply to the nippling down of the diverters. In 3 of the above 4 cases, diverters had been partly nippled down in substantially less time than 12 hours after the plug was bumped. It was fortunate for the rig crews that the diverters were able to be reconnected before the flow became prohibitive. The proper amount of time to leave the diverter system in place is dependent upon the time required for the cement to develop adequate strength to prevent gas flow. (Flows began in an average time of 4.5 hours and a maximum time of 10.5 hours after the plug was bumped in 13 of the incidents for which information was available.)

A better determination of the time required for waiting on cement would be based on lab tests of the cement properties rather than time alone. The Minerals Management Service plans to investigate the issue of waiting on cement. The goal is to better understand well bore cement properties, particularly compressive strength, and how they can be used to establish an acceptable criterion for waiting on cement. This could lead to a regulatory change that better recognizes cement performance criteria and the importance of when well control equipment is nippled down in lieu of the rigid waiting on cement time prior to drilling out of casing in our current regulations.

A Regional Offshore Technology Assessment Committee workshop has been planned for May 23, 1995, at the Lod Cook Alumni Center at Louisiana State University, in Baton Rouge, Louisiana. The forum will provide industry and MMS with the opportunity to discuss issues, concerns, and potential remedies regarding waiting on cement. This effort is a first step at better understanding cement properties and improving the ability to prevent shallow gas flows while waiting on cement.

The enclosed agenda for the workshop should be viewed as a guide to focus the discussions. Any recommendations for additional agenda items and participation by your company would be appreciated.

Enclosure

REVIEW OF 16 KNOWN SHALLOW GAS INCIDENTS

LSU/MMS
WELL CONTROL WORKSHOP
MAY 23, 1995

LEE FOWLER, MMS

MMS

INTRODUCTION

- DESCRIBE 16 SHALLOW GAS FLOWS WHICH OCCURRED DURING CEMENTING OPERATIONS
- DEPTH RANGE
- GEOGRAPHICAL LOCATION
- FREQUENCY OF OCCURRENCE
- SUMMARIZE EACH EVENT

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SHALLOW GAS EVENTS FOLLOWING CEMENTING OF CASING

EVENT	DATE	RIG TYPE	AREA	UPPER CASING (SS)	LOWER CASING (SS)	START N/D HRS	FLOW BEGAN HRS
1	9/16/65	PLATFORM	SM	-257	-2903	-	0
2	12/14/72	PLATFORM	SS	-547	-2483	?	?
3	10/1/75	DRILL SHIP	EI	-1051	-4035	?	?
4	3/15/76	PLATFORM	EI	-930	-2811	5.5	5.5
5	7/6/77	DRILL SHIP	SM	-691	-4622	5	10.5
6	2/14/78	JACKUP	MI	-996	-1926	-	3.5
7	6/1/79	JACKUP	WD	-899	-3920	-	1
8	5/26/83	PLATFORM	MC	-1823	-4160	-	0
9	10/21/83	JACKUP	GI	-1140	-3871	-	5.5
10	1/8/89	JACKUP	MP	-702	-1282	0.3	2.3
11	5/8/91	JACKUP	BA	-916	-3961	?	?
12	11/22/92	JACKUP	EI	-1001	-4676	7	8
13	2/25/93	JACKUP	MP	-369	-668	4.5	7
14	4/18/93	JACKUP	SS	-931	-4419	4	6
15	3/27/94	JACKUP	PN	-900	-5362	1.5	2.5
16	7/19/94	JACKUP	ST	-1319	-3229	-	5.5

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DEPTH RANGE OF EVENTS

- SETTING DEPTHS OF CONDUCTOR AND SURFACE CASING
- CONDUCTOR CASING WAS OMMITTED IN EVENTS 1 AND 13.
- DEPTH RANGE IS TYPICALLY 1000 FT TO 4500 FT

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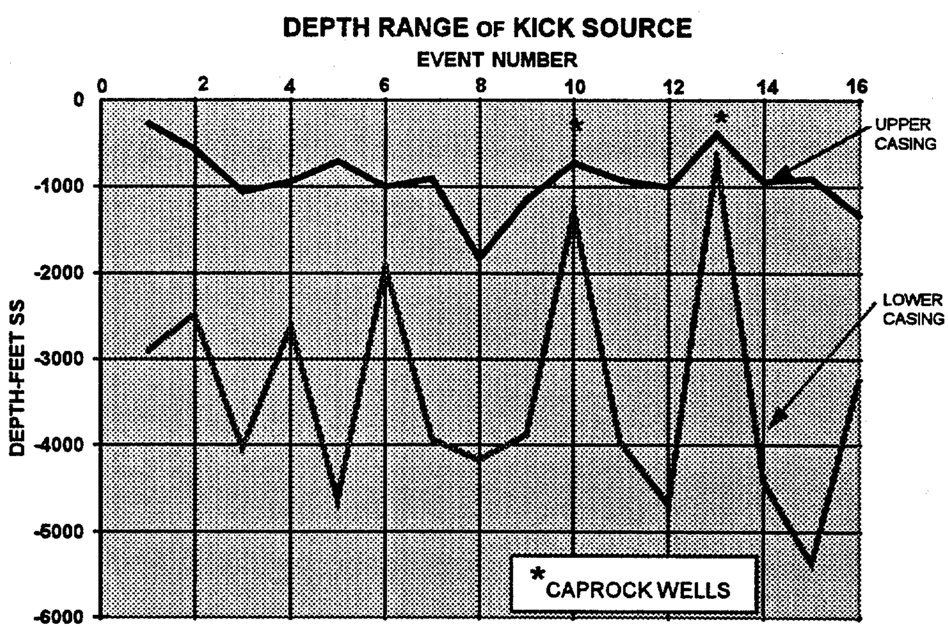

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GEOGRAPHICAL LOCATION

- LOCATION OF EVENTS IS FULL RANGE OF GOM OPERATIONS
- ADDITIONAL SHALLOW SANDS MAY HAVE BEEN CHARGED BY CASING LEAKS IN OLDER WELLS

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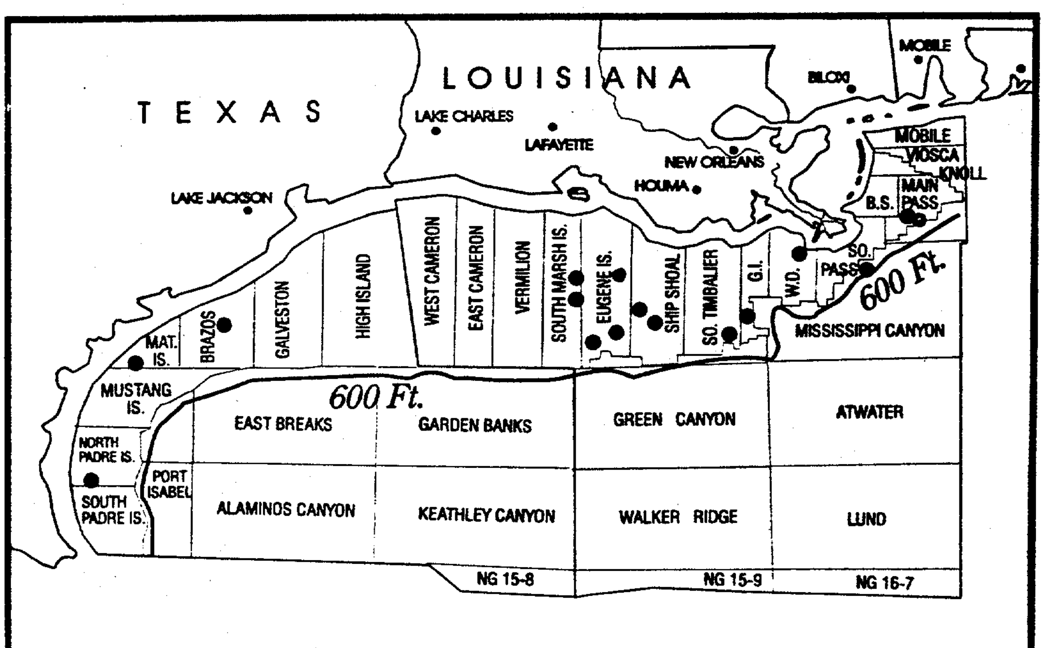
Shallow Gas Flows While Cementing Casings



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TECHNICAL APPRAISAL

- 34 TECHNICAL PAPERS AND ARTICLES ARE LISTED ON THE BIBLIOGRAPHY
- INCLUDES ARTICLES BY OPERATORS AS WELL AS CEMENTING COMPANIES

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SEE ATTACHED BIBIOGRAPHY

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FREQUENCY OF EVENTS

- GRAPH SHOWS 5 YEAR TOTALS
- WHEN FREQUENCY INCREASED IN 1975-1979, 2 SAFETY ALERTS WERE ISSUED
- ONE AND ONE HALF EVENTS OCCURRED PER FIVE YEAR PERIOD FROM 1980 - 1989
- FREQUENCY HAS JUMPED TO ALL TIME HIGH OF SIX EVENTS IN THE FIVE YEARS FROM 1990 -1994
- MORE AGRESSIVE DRILLING PROGRAMS
- LOSS OF EXPERIENCED PERSONNEL
- ADDITIONAL EXPOSURE DUE TO CHARGED ZONES
- HAVE ISSUED NEW SAFETY ALERT AND ARE HAVING THIS WORKSHOP
- NEED TO CONROL THIS PROBLEM NOW

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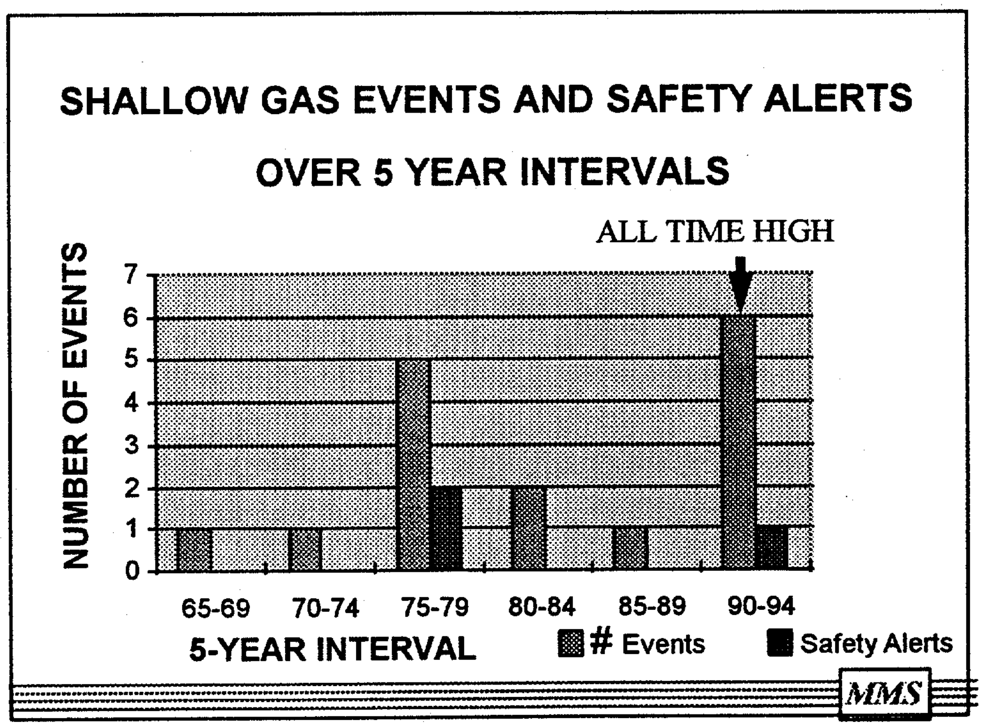
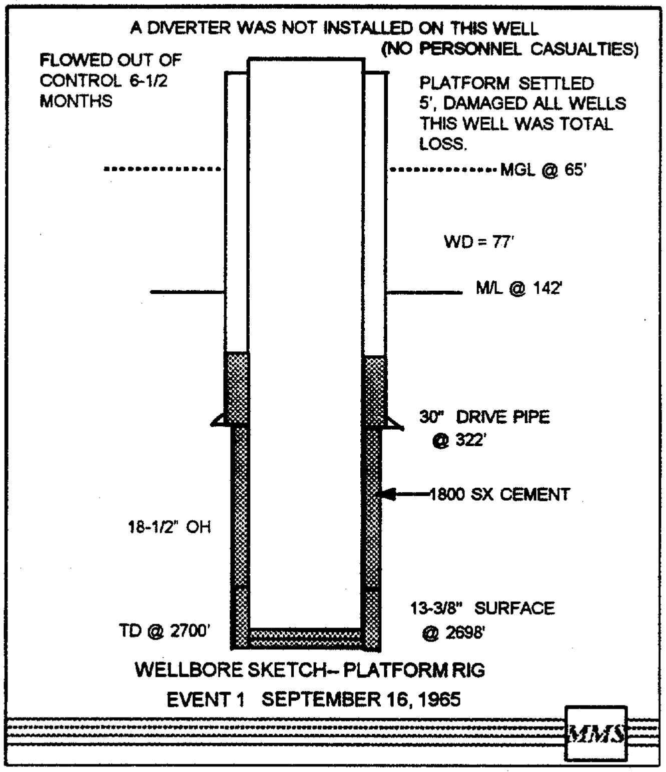




SOUTH MARSH ISLAND AREA

A DIVERTER WAS NOT USED ON THIS WELL

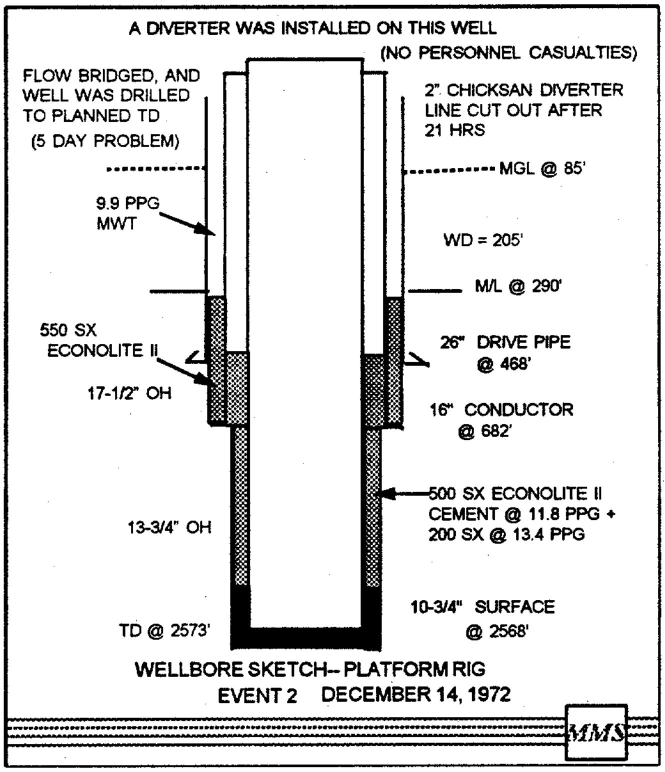
CONDUCTOR CASING WAS OMMITTED

PLATFORM SETTLED 5 FEET.

FIRST THREE WELLS ON PLATFORM SHEARED AT 500 FT (+/-)

FOURTH WELL WAS A TOTAL LOSS

PROBABLE CAUSE IS LISTED AS -
'PREMATURE DEHYDRATION OF CEMENT'



WELLBORE SKETCH-- PLATFORM RIG
EVENT 2 DECEMBER 14, 1972

SHIP SHOAL AREA

GOOD RETURNS DURING CEMENT JOB. (BUMPED PLUG).

THE BOP STACK HAD BEEN NIPPLED DOWN AND THE SLIPS AND PACKING SET.

WERE CUTTING THE 10-3/4" CASING PRIOR TO INSTALLING THE HEAD WHEN NOTED THAT FLUID WAS LEAKING THRU SLIPS AND PACKING

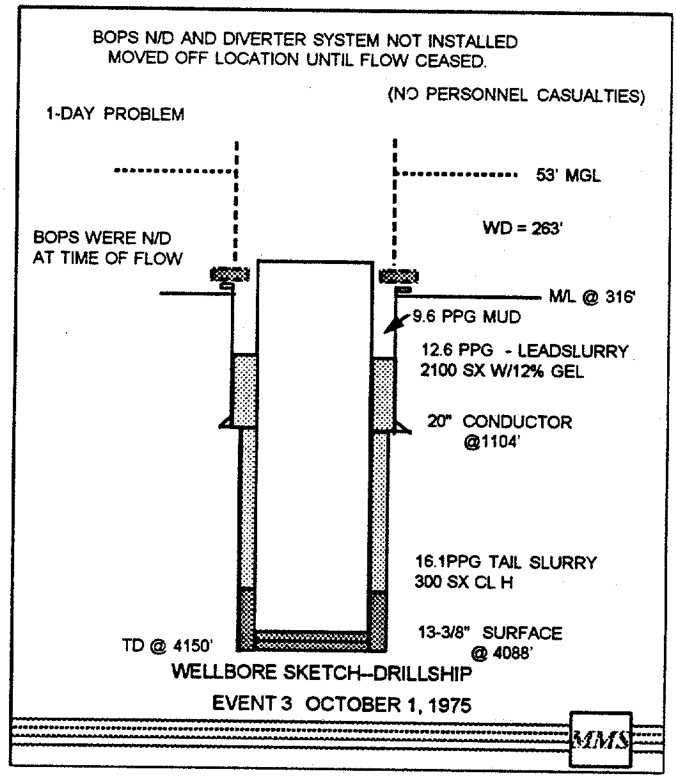
OPENED 2" DIVERTER VALVE ON 16" CASING HEAD, AND NOTED EXCESSIVE FLOW (LEAK THRU SLIPS AND PACKING STOPPED)

REMOVED CASING HEAD, N/U BOP STACK PLUS A 2" DIVERTER LINE. ABANDONED PLATFORM.

WELL BRIDGED 21HRS AFTER CIP.

REMANNED PLATFORM. 2" LINES WERE CUT OUT IN SEVERAL PLACES.

REPAIRED WELL AND RESUMED DRILLING APPROX 5 DAYS AFTER CIP (TESTED SHOE TO 12.5 PPG EMW).



EUGENE ISLAND AREA

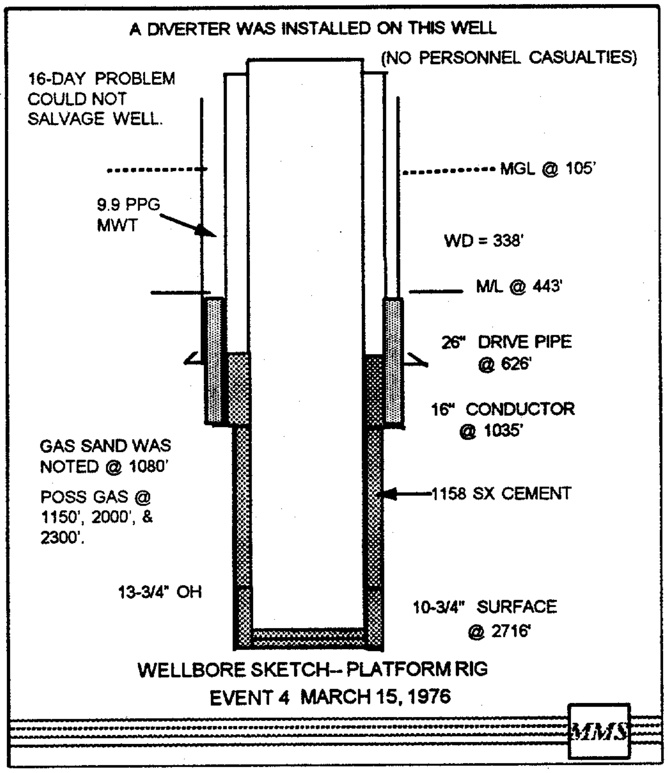
FOUR HOURS AFTER CEMENTING SURFACE CASING WHILE N/D BOPS GAS FLOW OCCURRED.

SHIP MOVED OFF OF LOCATION.

FLOW CEASED (3-1/2 HRS AFTER MOVE)

MOVED BACK TO LOCATION, DRILLED OUT.

TESTED , RECEMENTED, DRILLED OUT, AND RETESTED SURFACE CASING SHOE TO 14 PPG.



WELLBORE SKETCH-- PLATFORM RIG
EVENT 4 MARCH 15, 1976

EUGENE ISLAND AREA

FLOW OCCURRED WHILE NIPPLING DOWN RISER, 5-1/2 HRS AFTER CIP. REINSTALLED

RISER/DIVERTER AND DIVERTED THRU 2-6" VALVES.AND RUBBER HOSES.

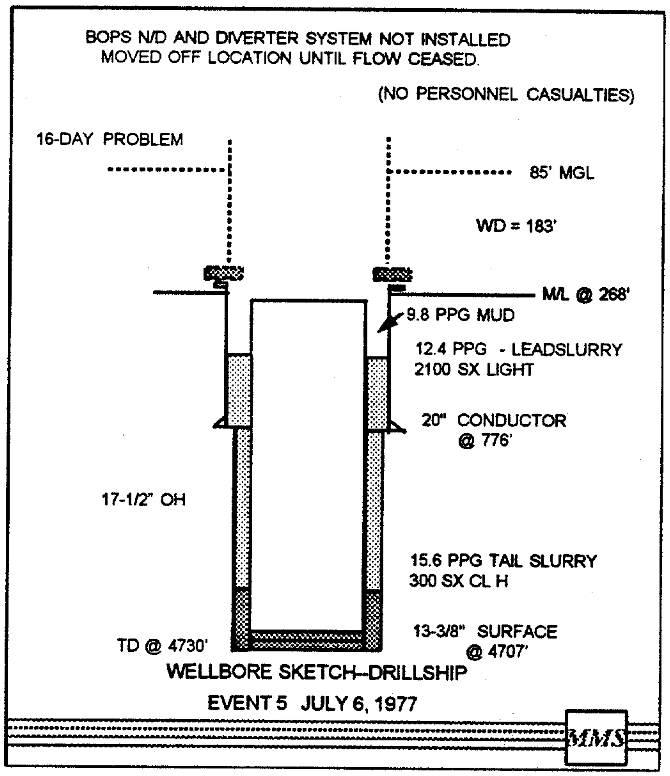
DIVERTER LINES FAILED, AND RIG WAS EVACUATED.

16 DAYS LATER, WELL WAS BROUGHT UNDER CONTROL.

WERE UNABLE TO SALVAGE THE WELL, PLUGGED AND ABANDONED AFTER 36 DAYS.

THE PLATFORM WAS SALVAGED AND RETURNED TO SERVICE.

RECOMMENDED USING LOW WATER LOSS, QUICK SETTING, FAST STRENGTH CEMENT



SOUTH MARSH ISLAND AREA

FLOW BEGAN 10-1/2 HRS AFTER CEMENT IN PLACE (CIP).

HAD PULLED STACK AND RISER.

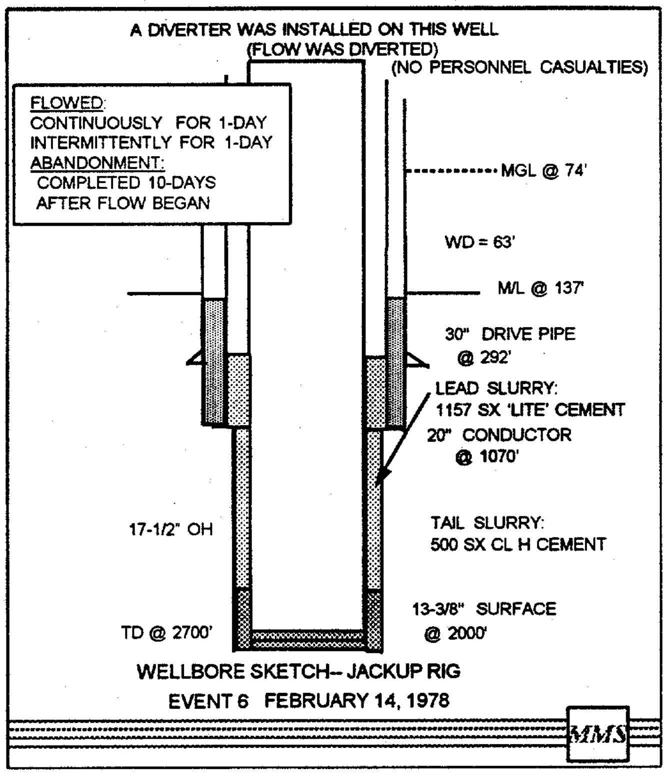
MOVED OFF LOCATION.

GAS BUBBLE WAS 75 FT IN DIAMETER.

USED A DERRICK BARGE TO LOWER 20-3/4" BOPS & CONTROL LINES AND SHUT WELL IN.

EVENTUALLY SALVAGED THE WELL.

16-DAY PROBLEM.



MATAGORDA ISLAND AREA

ANNULAR GAS FLOW HAPPENED 3-/12 HRS AFTER CIP.

DIVERTED WELL.

ATTEMPTED TO CLOSE THE DIVERTERS TO MOVE RIG BUT COULD NOT DO SO.

FLOWED CONTINUOUSLY FOR 1-DAY & INTERMITTENTLY FOR 1-DAY.

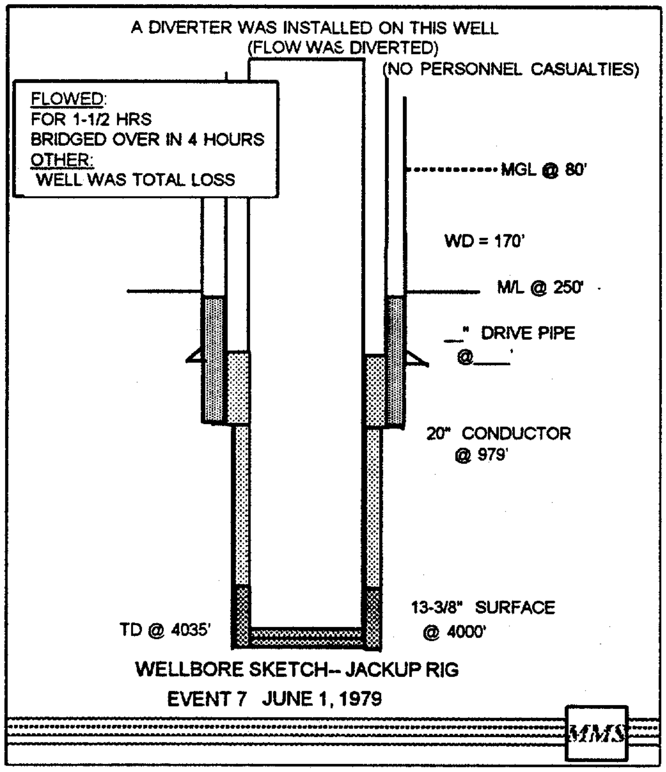
CUT OFF SURFACE EQUIPMENT ABOVE THE ANNULAR AND MOVED RIG OFF LOCATION.

WELL BRIDGED 7 DAYS AFTER CIP.

MOVED DERRICK BARGE NEXT TO WELL.

MUDDED UP CASING & GROUTED ANNULUS.

WELL WAS TEMPORARILY ABANDONED 10 DAYS AFTER CIP.



WEST DELTA AREA

AFTER CEMENTING SURFACE CASING, RAN 1" WASH PIPE TO CLEAN CMT FROM ANNULUS.

FLOW OCCURRED WHEN THREE JOINTS OF WASH PIPE WERE PULLED FROM ANNULUS.

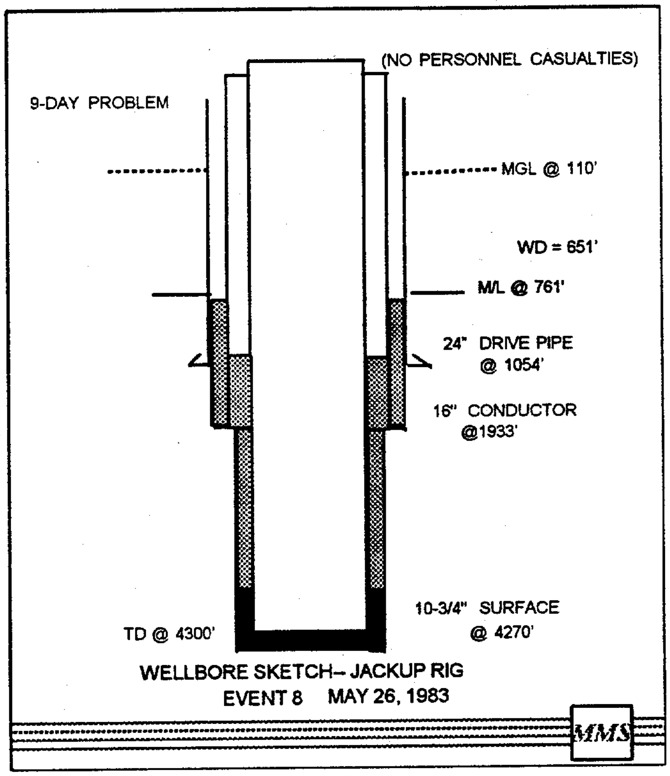
DIVERTED WELL, AND EVACUATED RIG.

AFTER 1-1/2 HRS DIVERTING, BOILING ACTION STARTED ON WATER SURFACE AROUND DRIVE PIPE.

WELL BRIDGED IN 4 HRS.

NO INJURIES TO PERSONNEL OR OTHER DAMAGE.

WELL WAS A TOTAL LOSS.

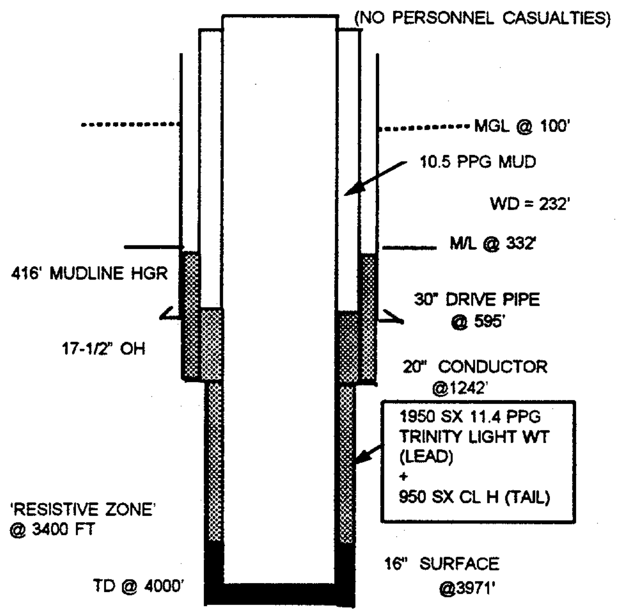


MISS. CANYON AREA

GAS PROBLEMS WERE NOTED FOLLOWING CEMENTING OF SURFACE CASING.

THE 10-3/4" CASING WAS FOUND TO BE PARTED AT 1933'.

ABANDONMENT OF THE WELL WAS COMPLETED 9 DAYS AFTER THE PROBLEM WAS NOTED.



WELLBORE SKETCH-- JACKUP RIG
EVENT 9 OCTOBER 25, 1983

GRAND ISLE AREA

TOP PLUG DID NOT BUMP, AND PARTIAL RETURNS WERE OBSERVED WHILE CMTG SURFACE CASING.

OBSERVED WELL FOR 20 MINUTES WITH NO FLOW.

OPENED PORTS IN MLH AND CIRCULATED SW TO CLEAN HGR.

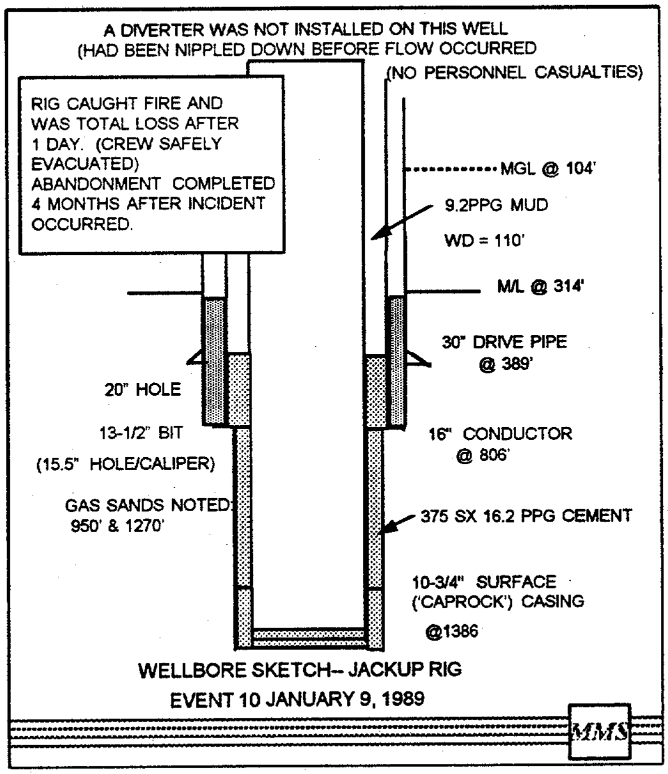
SPOTTED 20 BBL SUGAR WATER IN ANNULUS.

CLOSED PORTS, TESTED CSG TO 1500 PSI, AND WELL FLOWED.

DIVERTED WELL. EVACUATED RIG AFTER 16 HRS.

WELL BRIDGED 2 HRS LATER,

WELL WAS SALVAGED. RAN CBL, TEMP, & NOISE LOGS--RESISTIVE ZONE @ 3400'.



MAIN PASS AREA

4-1/2 HRS AFTER CIP, N/D BOP STACK.

6 HRS AFTER CIP PREPARING TO SET CSG SLIPS WHEN NOTED GAS

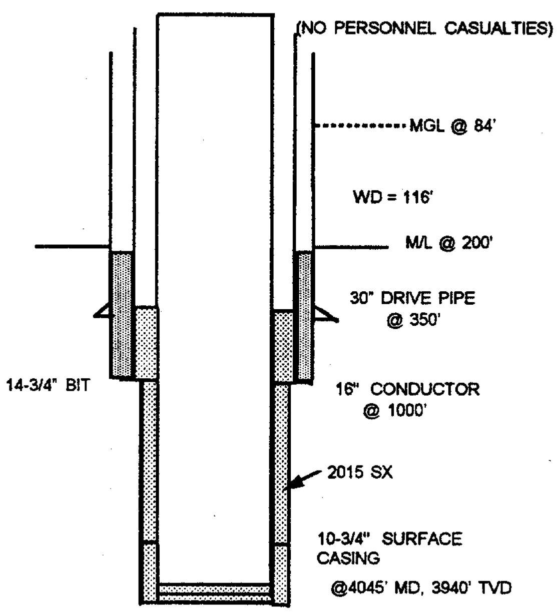
7-1/2 HRS AFTER CIP, WELL BEGAN FLOWING.

EVACUATED RIG IMMEDIATELY.

10 HRS AFTER CIP. WELL CAUGHT FIRE.

BY NEXT DAY RIG HAD COLLAPSED, FLAME BURNING VERTICALLY REACHING ESTIMATED HEIGHT OF 200 FEET.

ABANDONMENT COMPLETED 4 MONTHS AFTER INCIDENT OCCURRED.



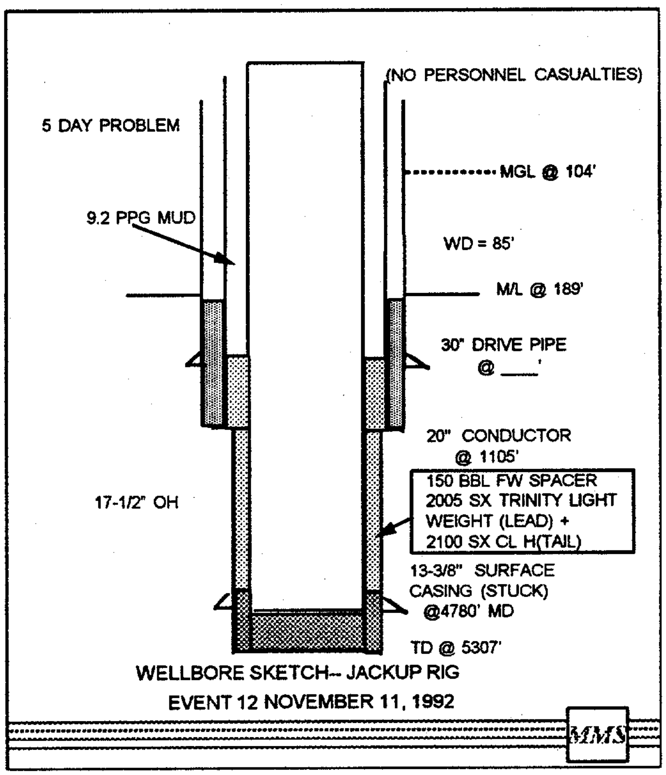
WELLBORE SKETCH-- JACKUP RIG
EVENT 11 MAY 8, 1991

BRAZOS AREA

GAS BEGAN CHANNELING THRU LEAD CEMENT.

DEVELOPED VERY WIDE AND PRODUCTIVE CHANNELS IN THE CEMENT SHEATH.

(INFORMATION ISVERY SKETCHY ON THIS EVENT)



EUGENE ISLAND AREA

CASING STUCK OFF BOTTOM & WAS CEMENTED. BUMPED PLUG AND FLOATS HELD

WOC 7 HRS, N/D DIVERTER. WELL STARTED TO FLOW ON SURFACE X CONDUCTOR ANNULUS.

N/U DIVERTER & LINES. DIVERTED WELL.

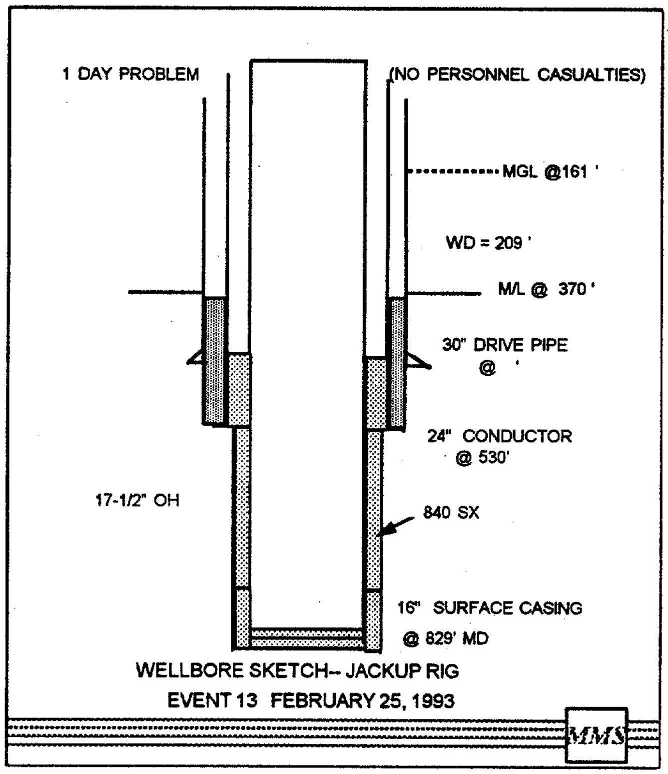
FLOW WAS INTERMITTENT. SWI W/ PRESS B/U TO 82 PSI AND FALL OFF TO 45 PSI.

LUBRICATED 12 BBL 9.2 PPG MUD

RAN GROUT STRINGS, FOUND CMT @ 75'.

GROUTED W/42 SX CL H + 2% $CaCl_2$.

RESUMED DRLG 5 DAYS AFTER FLOW BEGAN.



MAIN PASS AREA

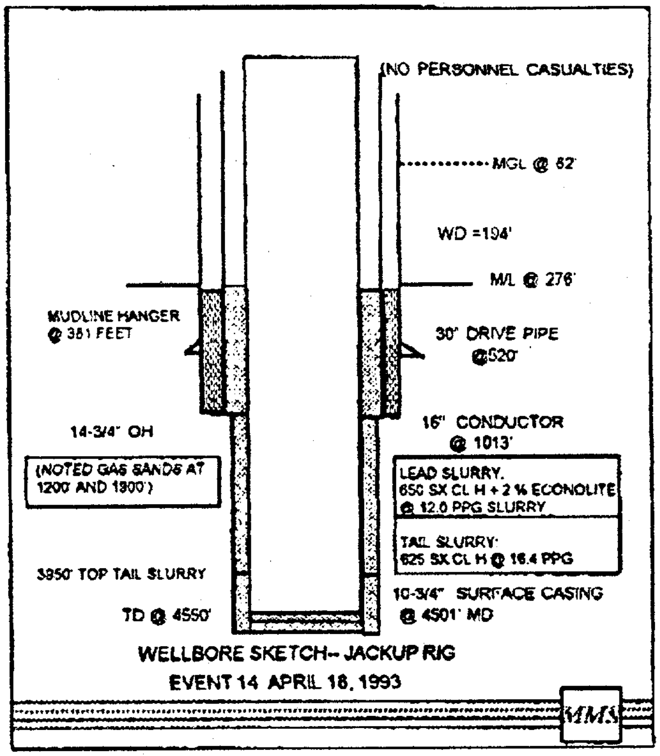
REMOVED BOPS 7 HRS AFTER CEMENT IN PLACE ON 16" CASING

WELL UNLOADED.

EVACUATED RIG.

AFTER 20 HOURS WELL WAS DEAD

WELL PERMANENTLY ABANDONED.



WELLBORE SKETCH-- JACKUP RIG
EVENT 14 APRIL 18, 1993

SHIP SHOAL AREA

4 HRS AFTER CIP, N/D DIVERTER SYSTEM.

WASHED CEMENT FROM ANNULUS USING 1-1/4" TBG AND SPOTTED 40 BBL SUGAR WATER IN ANNULUS ABOVE MUDLINE HANGER.

5-1/2 HRS AFTER CIP, WELL BEGAN TO FLOW.

REBOLTED DIVERTER AND DIVERTED WELL.

7 DAYS AFTER CIP, DISCONNECTED ABOVE DIVERTER AND MOVED RIG OFF LOCATION.

4-1/2 MONTHS AFTER CIP, STARTED ABANDONMENT OPERATIONS -- (7 DAYS)

RECOMMENDATIONS FOR NEXT WELL IN THIS AREA:

HAVE 300 BBLS KILL MUD ON LOCATION PRIOR TO DRILLING GAS SAND.

RUN MUD LOG ON HOLE FROM DRIVE PIPE TO TD

ENSURE PROPER FILL UPS

DRILL THRU SHALLOW HAZARD AND CIRCULATE BOTTOMS UP

USE A LOW WATER LOSS LEAD CEMENT WITH A QUICK TRANSITION

RUN A PROPERLY WEIGHTED SPACER.

CLEAN OUT ABOVE THE MLH WITH MUD RATHER THAN WATER.

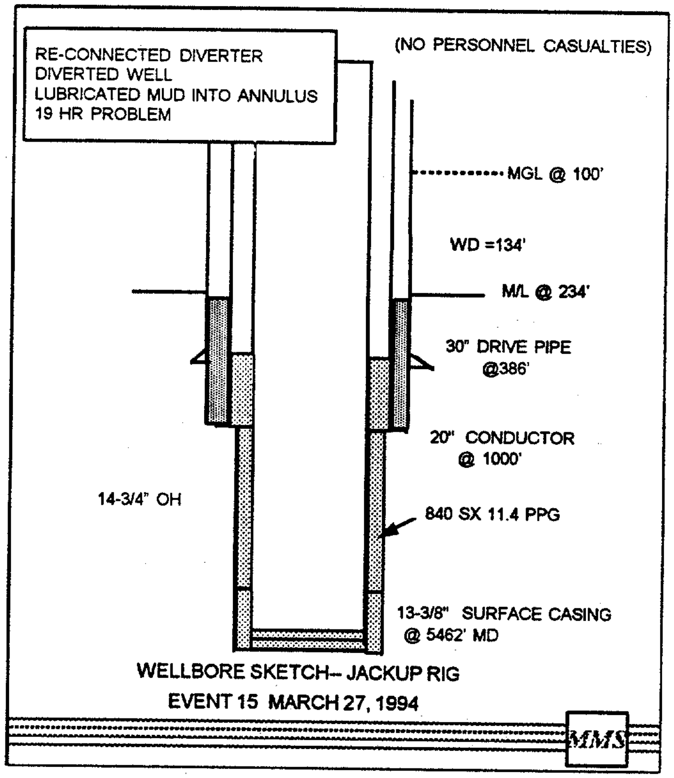
AFTER CMT JOB, SWI AND HOLD PRESSURE @ 50-100 PSI

WOC 24 HRS!!

RUN CENTRALIZERS ACROSS SHALLOW HAZARDS AND CONDUCTOR LAP.

RUN LESS TAIL CEMENT.

RUN LEAD CEMENT 200 FT INSIDE CONDUCTOR.



NORTH PADRE ISLAND AREA

2 HRS AFTER CIP, NIPPLED DOWN DIVERTERS

WHILE CUTTING 13-3/8" CSG, SMALL FLOW FROM ANNULAR CSG VALVE OCCURRED.

REINSTALLED DIVERTER

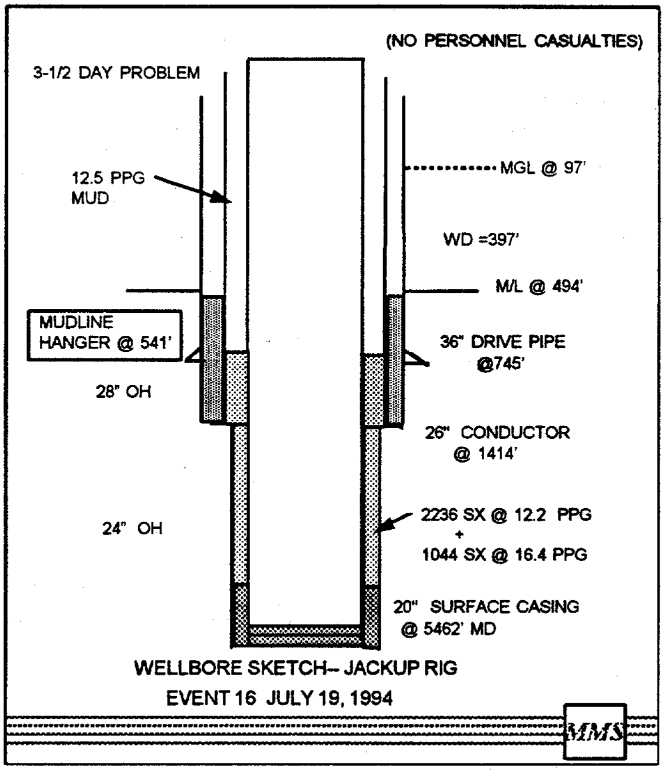
CASING SLIPS FAILED, MUD & GAS FLOWED THRU DIVERTER LINE

LUBICATED 8.34 BBL 9.4 PPG FLUID INTO ANNULUS.

WELL DIED

RECOMMENDATION:

WAIT MINIMUM OF 4 HRS BEFORE N/D DIVERTER.



WELLBORE SKETCH-- JACKUP RIG
EVENT 16 JULY 19, 1994

SOUTH TIMBALIER AREA

PLANNED AS 18000' WELL--20" SURFACE CASING

DID NOT BUMP TOP PLUG

AFTER CMTG OPENED PORTS ON MUDLING HANGER AN DISPLACEDANNULUS W/200 BBLS LIGNO WATER

WELL STARTED FLOWING ON ANNULUS (AFTER RUNNING GYRO SURVEY)

CLOSED WELL IN, MAX PRESSURE 140 PSI. BLED PRESSURE.

COULD NOT PUMP INTO ANNULUS W/ 150 PSI.

COULD NOT BACK OUT AT MLH

RAN 3/4" TUBING TO 460' AND CIRCULATED ANNULUS W/ 18 PPG MUD.

RESUMED DRILLING OPERATIONS

Current MMS Regulatory Requirements

Shallow Gas Flows While
Waiting on Cement
May 23, 1995

MMS

Performance Requirements

- 30 CFR 250.3 - Performance Requirements
- Use of new or alternative techniques, procedures, equipment or activities if comparable or better in terms of safety, performance, protection
  - prior written approval from MMS required
- Departures when necessary for well control, proper development, conservation, protection of the human and marine environment
- Incorporation of industry recommended practices and standards

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Drilling Regulations

- 30 CFR 250, Subpart D - "Oil and Gas Drilling Operations"
- Control of Wells - 30 CFR 250.50
  - necessary precautions to keep well under control at all times
- Application for Permit to Drill - 30 CFR 250.64
  - Well design
  - Shallow Hazards review (site survey, offset data, etc.)
  - Well Control procedures/plans
- Well Casing and Cementing - 30 CFR 250.54
- Pressure Testing of Casing - 30 CFR 250.55
- Diverter Systems - 30 CFR 250.59

MMS

Well Casing and Cementing

- Performance based criteria for design
- Protect fresh water aquifers, isolate hydrocarbon zones, control formation pressures and fluids
- Set casing above known shallow gas sand
  - case by case review otherwise
- Cement in bottom 500 feet of casing annulus designed to achieve a minimum compressive strength of 500 psi
- Evaluate casing/cement integrity
- Remedial actions as necessary

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Cement Requirements

Drive	to mudline (if drilled)
Conductor	to mudline
Surface	200' inside conductor
Intermediate	500' above isolation zone or shoe
Production	500' above uppermost hydrocarbon zone
Liner	100' into previous casing

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Pressure Testing

- □ 70 percent of casing MIYP
  - or as otherwise approved by the District Supervisor (maximum anticipated surface pressure)
  - conductor can be tested to minimum 200 psi (MMS policy)
- □ Remedial action if pressure declines more than 10 percent in 30 minutes
- □ Liner lap tested to minimum 500 psi above fracture pressure of formation

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Diverter systems

- **Regulations cover size, configuration, maintenance, actuation and pressure testing**
- **Installation on all rigs while drilling conductor and surface hole**
- **Designed, installed, and maintained to divert gases, water, mud, and other materials away from the facility and personnel**

MMS

Waiting on Cement

- **Fixed time before resuming drilling**
  - 8 hours under pressure for conductor casing
  - 12 hours under pressure for all other strings
- **Regulations do not address WOC in terms of waiting to nipple down diverters or BOP**
- **Informal pole of operators in GOM regarding nipple down time**
  - wide range of criteria for nipple-down decisions

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MMS Safety Alerts

- 1976 - Notice No. 43: "*Shallow Gas Blowout*"
  - BOP removed after 5.5 hours
  - change in cement resulting in loss of hydrostatic head pressure (excessive water loss to porous zone causing cement to bridge)
  - reference SPE 4783 "Inability of Unset Cement to Control Formation Pressure" (W.H. Stone, W.W. Christian)
- 1977 - Notice No. 66: "*Blowouts from Surface Casing - Conductor Annulus*"
  - several hours after nippling down the BOP stack
  - loss of hydrostatic head of the cement column due to cement dehydration across permeable zone or entering thief zone
  - 8 precautions to prevent future occurrence

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MMS Safety Alerts - (cont'd)

- 1995 - Notice No. 165: "*Shallow Gas Flows While Cementing Surface Casing*"
  - summarizes 5 recent events
  - diverter was nippled down prior to flow in several events
  - cement transition before compressive strength developed
  - several considerations included for wells in shallow gas areas
  - need better determination of time required for WOC for nippling down diverters and before drilling out casing
  - workshop announcement

MMS

MAIN ENERGY, INC.
1111 FANNIN, SUITE 1340
HOUSTON, TEXAS 77002
(713) 759-1144
FAX (713) 759-2094

MINERALS MANAGEMENT SERVICE
RECEIVED
APR 27 1995
MS 5221
Gulf of Mexico OCS Region, New Orleans, La.

April 24, 1995

Mr. James B. Regg
Petroleum Engineer
Minerals Management Service
Field Operations
1201 Elmwood Park Boulevard
New Orleans, LA 70123-2394

Re: Shallow gas blowouts after cementing

Dear Jim:

This is the paper that details a case history with the times documented. The reason I wrote the paper was to alert the industry to a little understood phenomenon. Most people assume that a cement column mixed at a higher density than the drilling mud will contain formation pressure.

Although this paper was presented at both the AIME Symposium on Formation Damage Control and the SPE Fall Meeting in 1974, the SPE did not think the problem was of significant consequence. The paper did not have enough "integral signs."

I also have additional specific data about this particular blowout. Please call me anytime if you have any questions or comments.

Very truly yours,

William H. Stone
Vice President

WHS:ban
Enclosure

Bill\Regg\Ltr. (4/24/95)

SOCIETY OF PETROLEUM ENGINEERS OF AIME
6200 North Central Expressway
Dallas, Texas 75206

PAPER NUMBER SPE 4783

THIS IS A PREPRINT --- SUBJECT TO CORRECTION

The Inability of Unset Cement to Control Formation Pressure

William M. Stone, Union Oil Co. of California, and
William W. Christian, Halliburton Services, Members AIME

INTRODUCTION

The migration of gas through a cemented annulus was not appreciated until the problem arose during the mid 1960's in gas storage wells. The communication of gas in these wells resulted in wellbore analysis to determine the apparent cause of leakage. This analysis developed the idea that the problem was related to cement-casing-formation interfaces and the bonding between them.[1-3] At this time, the solution was thought to be better displacement of drilling fluids by cement and prevention of channeling.[4-6] However, in the past few years, with the advent of deeper well completions across high pressure gas zones with small or negative pressure differentials, the problem of formation damage and annular blowouts or pressures has become more prevalent and new theories evolved. This paper will describe a blowout that illustrates this problem.

The most accepted theory to this problem is the inability of the cement column to effectively transmit the hydrostatic pressure to the formation containing the gas. The physical characteristics of cement such as density, setting, dehydration, bridging and gelation are the determining factors for gas migration. Any one of these properties may cause the migration even though more than one may actually be occurring in a well at the same time.

References at end of paper.

The density of the fluid column must exert a pressure greater than the formation pressure of a permeable zone to prevent liquid migration into the wellbore. In order to have gas cutting of cement, it is necessary for the gas pressure to exceed the pressure exerted by the hydrostatic head of a liquid cement column. Therefore, it is necessary for the density of the cement column and the drilling muds and flushes, either separately or in combination, to exceed the formation gas pressure to prevent it from entering the annulus. This is generally known.

LABORATORY DATA

Laboratory tests have indicated that it would be impossible to have gas leakage through a column of cement when the hydrostatic pressure is greater than the gas pressure.[7] As one would expect, though, if the gas pressure is increased above the hydrostatic pressure while the cement is in a fluid state, leakage into the wellbore can occur, but will cease upon a decrease in the gas pressure toward the annulus. However, when the gas pressure is higher than the hydrostatic pressure after the cement has taken an initial set, a channel may be formed and gas will continue to migrate up the annulus with a decrease in gas pressure as a result of the low hydrostatic pressure in this gas flow channel.

Therefore, once a gas channel is formed, the migration will continue up the annulus unless an impermeable barrier is met.

Cement Filtration Control

Cement dehydration is considered the second most important factor contributing to gas migration in a wellbore. This condition depends predominately upon driving force, differential pressure, formation permeability, and cement filtration rate control.

In order for cement dehydration to occur in a wellbore and permit gas leakage, there must first be permeable formations above the gas interval. The hydrostatic head should exceed the formation pressure to initiate building a cement filter cake. In turn, the bridging of the cement particles against the formation interface by losing filtrate from the slurry will begin to support the cement column above this point. Subsequently, the cement slurry below this point in the wellbore will only have to lose a very small volume of filtrate into another permeable zone to decrease the pressure. When this pressure becomes equal to or less than the highest pressure gas reservoir, it would take only a short time for gas to start entering the wellbore since the hydrostatic head has been reduced.

Once gas starts to migrate up the cement column, it results in a further lowering of the hydrostatic pressure, which in turn increases the rate of gas channeling. When the gas reaches the initial bridging point up the hole, the cement may not be set solidly and the gas accumulating in this area could build up to a pressure causing channeling either through the weak cement column or into the permeable zone on which the filter cake is built. If the gas enters the permeable zone, it would start pressuring this zone, and since the cement in the annulus may not be set or bonded in this early stage, the gas could bypass the bridge and re-enter the unset cement column at the top of this zone where the hydrostatic pressure would be relatively low due to the lesser column of fluid. This could result in total gas cutting or channeling in the annulus that could show up at the surface.

Bridging

Bridging of particles during cementing operations may restrict the effective hydrostatic pressure.[8] This may occur at any location in a wellbore, but could also happen at the top of the hanger in a liner job. Factors influencing bridging may be attributed primarily to sloughing formations or mud filter cake.

Annulus bridging up the hole is similar to dehydration when considering gas diffusion into a wellbore. If bridging occurs during primary cementing, prior to complete displacement, the possibility of losing returns is increased and, in turn, may result in a loss of hydrostatic pressure. This type of bridging may also leave cement inside the casing string that would require drilling out.

Gelation

Due to the thixotropic properties, gelation of cement or drilling mud up the hole is another factor to consider with regard to the lowering of the hydrostatic head. When cement is mixed with water, a chemical reaction is initiated and in the setting process, the slurry proceeds from a pumpable composition to a set material. During this change of phase, gelation or a significant increase in viscosity may occur. The period of time the cement remains as a gel depends upon temperature, cementing composition, pressure and water-cement ratio.

CASE HISTORY

With the above thoughts in mind, let us review the sequence of events preceding and during an actual offshore Louisiana blowout that appears to be a result of the inability of cement to transmit hydrostatic pressure. This well was being drilled to develop shallow gas sands in the Ship Shoal area. The occurrences of gas sands in the surface hole of the first two wells drilled from the platform necessitated that 16-in. conductor pipe be set at 682 or 392-ft penetration below the mud line. A 13½-in. hole was drilled to 2,573 ft with a maximum mud density of 9.9 lb/gal and logged. Then 10 3/4-in. surface casing was run to 2,568 ft. The hole was circulated clean. It was cemented with 500 sacks of a light-weight cement mixed to an 11.8-lb/gal density followed by 200 sacks mixed at 13.4-lb/gal density. The cement was in place at 6:00 a.m. with good cement returns to the surface.

The hookwall slips were then set, the pipe cut and dressed. The hole was full. The packoff would not go over the pipe because the pipe was out of round. At 11:00 a.m., while attempting to install the packoff, the well began to drip cement out of the starting head outlet. Since this drip was thought to be caused by heat expansion, the valve on the outlet was closed. However, the cement began to flow slowly past the slips. Apparently, either the out-of-round casing or the lack of weight on the slips prevented the hanger seals from sealing. The outlet valve was opened and a small amount of pressure was bled off. An attempt was made until 11:30 a.m. to install the packoff. During this time the flow rate steadily increased. The blowout preventers were quickly reinstalled on the starting head with the blind rams closed. By 12:00 noon, the well was flowing a solid stream of cement with an occasional gas head through the vent line over the side of the platform. At 1:30 p.m. the well bridged for 30 minutes. When the bridge broke, it flowed gas with cement slugs weighing 10.9 lb/gal. The platform was abandoned at 4:00 p.m. The well bridged permanently during the night between 11:30 p.m. and 2:30 a.m.

This sequence of events appears to be a text-book example of the theory presented above. The gamma-ray induction log shows three gas sands and several water sands. All of the parameters are present to support this theory as the explanation for the blowout.

CONCLUSIONS

The fact that formation fluids will migrate into a wellbore when a pressure differential exists toward the wellbore is a basic physical law and has been proved in laboratory experiments. The subject well's surface hole was drilled with a maximum mud density of 9.9-lb/gal. Since the well did not flow at this time, it is a valid assumption that the 9.9-lb/gal mud density was sufficient to prevent the flow of gas into the wellbore. The surface pipe annulus was then displaced to the surface with 11.8-lb/gal density cement that certainly should have exerted an adequate hydrostatic pressure upon the permeable formations to prevent any flow into the annulus. However, after the cement had been in place for 5 hours, the annulus began to flow. This could only have occurred if the cement did not transmit its 11.8-lb/gal hydrostatic pressure to the gas sands in this well.

Recent experiments demonstrate that the physical characteristics of cement such as density, setting time, dehydration, bridging and gelation are the contributing factors that cause this inability of the cement to transmit its hydrostatic pressure. Since the conditions in the subject well were analogous to the laboratory conditions, it is logical to assume this was the reason for the blowout.

RECOMMENDATIONS

The first step in the elimination or minimization of this problem is to determine if the necessary conditions exist for this type of blowout to occur. This can be done by logging the hole. If gas sands were present, then the following measures should be taken by the well operator as well as the usual safe operating procedures.

After the casing is run, the hole should be excessively circulated to condition the mud and to remove any gas that may have entered the wellbore. Then the following cementing practices should be observed. The two most important factors to control at all times are fluid column density (hydrostatic head exceeding gas pressure) and fast-setting cements having filtration control. Cements possessing low fluid loss characteristics are very desirable in any gas well completion.[8,9]

Factors found to be beneficial in reducing gas migration into an annulus during and after primary cementing are, (1) mud or cement density greater than wellbore pressure, (2) cement filtration control, (3) cement setting or changing from a slurry to a solid in a minimum time after placement (cement not overretarded), (4) pipe movement during displacement, (5) increased flow rates during displacement, (6) centralization of casing string in hole, (7) scratchers employed across washout sections if possible, and (8) two-stage cementing utilizing a unit-type casinghead if required for maximum safety.

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GEOLOGICAL SURVEY
GULF OF MEXICO AREA
OFFICE OF THE OIL AND GAS SUPERVISOR
FIELD OPERATIONS

NOTICE NO. 43
June 21, 1976

OCS OPERATIONS SAFETY ALERT

SHALLOW GAS BLOWOUT

A shallow gas blowout recently occurred on an offshore platform drilling rig. A string of 10 3/4" casing had been run and cemented at 2716'. After 5 1/2 hours was allowed for the cement to set, the blowout preventer was removed. During subsequent operations to rig down the riser the well started flowing dry gas through the 10 3/4" x 16" annulus. Attempts to control the flow were unsuccessful and the platform was abandoned. The well was brought under control sixteen days later with no injury to personnel and no fire or pollution.

The operator believes the primary cause of this gas flow was a change which occurred to the cement resulting in a loss of hydrostatic head pressure against the gas zone. It is believed that an excessive water loss into a porous zone resulted in bridging of the cement which caused the loss of hydrostatic pressure and permitted the gas to enter the well and channel its way to the surface. The operator states this phenomenon is described in the technical paper: William H. Stone and William W. Christian, The Inability of Unset Cement to Control Formation Pressure, SPE 4783, Society of Petroleum Engineers.

In order to prevent a recurrence of this type accident the operator is taking the following actions:

1. Use low water loss, quick setting, fast strength cement.
2. Reciprocate casing during cementing operation.

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GEOLOGICAL SURVEY
GULF OF MEXICO AREA
OFFICE OF THE OIL AND GAS SUPERVISOR
FIELD OPERATIONS

NOTICE NO. 66
September 26, 1977

OCS OPERATIONS SAFETY ALERT

BLOWOUTS FROM SURFACE CASING-CONDUCTOR CASING ANNULUS

Recently, several operators have encountered a significant shallow gas flow from the annulus between conductor and surface casing. This flow has occurred several hours subsequent to cementing surface casing while nippling down the B.O.P. stack. In some cases, drilling personnel have had to abandon the drilling facility, or move the drilling vessel off location.

This delayed flow of gas is believed to develop because of a loss of hydrostatic head of the cement column, caused by the cement slurry either dehydrating across permeable zones, or entering a weak or thief zone. This leads to migration of gas upward through small channels in the cement-in-place, or through channels outside the cement-in-place, once the hydrostatic head becomes less than the pressure of any gas bearing zones that have been drilled through. Once this migration up the cement column starts, it results in an additional lowering of the hydrostatic head, which further increases the rate of channeling, until at some point in time there is sufficient loss of hydrostatic head so that a blowout occurs.

If an operator has a well in which there are possible permeable zones in the shallower portion of the open hole, precautions must be taken to prevent the occurrence of this type blowout. The first precaution would be to examine an electrical log of the hole to determine the existence and location of these potential problem zones. If gas sands are exposed, then procedures such as the following are used in order to prevent or minimize the delayed gas flow occurrence:

1. Run the casing using centralizers.
2. After the surface casing is run the casing annulus is thoroughly circulated to remove any gas cut mud and to condition the hole prior to cementing.
3. Use of a low weight cement slurry followed by class H neat tail-in.
4. Use of a fluid loss additive or gel cement to control excessive cement water loss to permeable zones and minimize undesirable dehydration.
5. Reciprocate or rotate casing or both, if feasible.
6. Consideration should be given to using a two stage cementing tool, if necessary.
7. Monitor returns constantly while cementing to detect partial or lost returns or other undesirable occurrences, in order to determine the necessity of running a cement bond log or temperature log and performing remedial cementing prior to removing the B.O.P. stack.
8. Observe annulus flow or pressure after cementing for 6-8 hours or until a cement compression strength of 500-700 psi is reached to determine whether or not to remove the B.O.P. stack entirely. The B.O.P. stack might be partially nippled down, but only to the extent that it can still be used for safely controlling and bleeding off a delayed gas flow.

The above could help prevent this type blowout where potential delayed gas flow conditions exist. The applicability of this safety alert should be determined by each OCS Operator after a thorough review of his particular drilling procedures.

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Technical Considerations

- ☐ Mechanisms involved with gas migration while Waiting on Cement
- ☐ Wellbore considerations
  - hole cleaning and stability prior to cementing
  - length of cement column
  - cement placement techniques
- ☐ Define Set-up Time for conductor and surface casing cement
- ☐ What considerations and cement properties can be used to establish effective WOC?
- ☐ Should diverter nipple down time be tied to WOC?

MMS

Technical Considerations - (cont'd)

- ☐ Fluid loss, density, transition time, slurry composition
  - effect on preventing annular gas migration
  - new cement slurry designs to mitigate
- ☐ Compressive strength
  - minimum strength necessary to prevent gas migration?
  - what factors affect compressive strength?
  - can it be effectively and accurately measured (lab; field)?
  - is it a viable criterion for defining WOC?
- ☐ WOC criteria different for different operations?
  - normal drilling
  - coiled tubing applications (squeezes, CT drilling, etc.)

MMS

Operational Considerations

- ☐ **Avoidance based on shallow hazards information**
  - data and technology concerns
- ☐ **Predictive techniques**
  - modeling to determine annular gas migration potential
- ☐ **Contingency Planning**
  - inclusion with the APD
  - gas handling procedures
  - divert vs. shut-in and associated considerations (e.g., LOT)
- ☐ **Diagnostic techniques**
  - signatures while cementing progresses
- ☐ **Other Operational considerations**

MMS

Next Step?

- ☐ **Cement composition for conductor/surface casing?**
- ☐ **Proper time to leave diverter/BOP nippled up after cementing conductor/surface casing?**
- ☐ **Basis for WOC?**
  - rigid time frame
  - measurable cement performance properties
  - combination
- ☐ **Areas where more research is needed?**
  - procedures, tools, slurry design, other areas?
- ☐ **Interim approach to mitigating shallow gas flows while cementing conductor and surface casing?**

MMS

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Essential Elements of a Blowout Contingency Plan

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Summary / Introduction

This paper presents the essential elements of a blowout contingency plan. It does not give specific types of kill and control operations, but is a general plan and guideline for the creation of a properly constructed blowout contingency plan. The key ingredients of will be a predetermined plan of action along with a means to support the logistics required for a blowout project.

Justification for a Contingency Plan

No matter how well conceived a drilling or production plan is for the prevention of loss of control of oil and gas wells, there will always be the chance that a blowout will occur. If it can happen, it will. The question then becomes when and how severe. An emergency preparedness plan, hereafter referred to as the Blowout Contingency Plan (BCP), should be prepared prior to drilling or producing of wells with the potential to blowout.

This is not a new concept, Sun Tzu[1], a Chinese general for the Kingdom of Wu (Circa 500 B.C.), said of laying plans some 2500 years ago: "the general who wins a battle makes many plans in his temple before the battle is fought. The general who loses a battle makes but a few calculations beforehand".

To be efficient and effective in controlling a major blowout much planning is required. The control project is very much like being in a major battle as it often requires massive efforts and must be accomplished on a fast-track basis. In some cases, there is little time to enact the plan before opportunities are lost, and even less time to create the plan.

Fortunately, major blowouts are fairly infrequent. Unfortunately, this infrequency leaves the operational staff of the oil operator inexperienced in controlling blowouts. Generally, they rely on outside experts who deal with these matters on a regular basis. The industry is moving toward higher pressure and higher technology wells. These wells, offering greater technological challenges as water depth, pressure, and temperature increase, invalidate most traditional well-control company experience and level of technology. Therefore, the responsibility of pre-engineering and planning for regaining control falls clearly on the operating company. As they are ultimately responsible for a well control event.

A control effort will place a tremendous burden on many of the assets of the company. The major considerations are the demands on manpower, equipment, and finances. Most corporations maintain risk management positions so that large portions of the costs will be covered by insurance. However, in some cases, considerable time may pass before the actual losses are reimbursed. Thus, the company will have to provide the funds and logistical support to control the well. In major events this can be quite substantial.

The costs of control or the losses associated with fires and explosions in production operations are difficult to document as this information is not freely distributed nor is it generally in the public domain. Table 1 lists a limited number of control events that have occurred along with the approximate loss amounts. Note that some of the figures are gross approximations and none include reserve losses. Some figures include the loss of the platform.

Given the monetary cost of controlling a well, it is reasonable to expend engineering and pre-planning effort to create a plan for control that will have the effect of reducing the cost of killing a blowout well.

Components of the Blowout Contingency Plan

The intention of any Blowout Contingency Plan (BCP) should be to give valuable assistance in the solution of the well control event if it should happen. The BCP cannot be complete in every detail, but it can give guidance and outline a general action plan.

TABLE 1: Cost of Control Costs††
(Random Wells in Various Locations)

Well Type / Locations	Year	Est'd Costs (USD)
Offshore, Gulf of Mexico	circa 1960	$20,000,000
Offshore, Gulf of Mexico	1974	22,000,000
Offshore Platform, North Sea	1976	56,000,000
Offshore, Gulf of Mexico	1977	12,000,000
Offshore, Arabian Gulf	1978	65,000,000
Offshore, W. Africa	1978	90,000,000
Offshore, Gulf of Mexico	1978	85,000,000
Onshore, N. America	1978	20,000,000
Onshore, N. America	1979	15,000,000
Offshore, Arabian Gulf	1980	22,000,000
Onshore, N. America	circa 1980	50,000,000
Offshore, Gulf of Mexico	circa 1980	15,000,000
Offshore, Gulf of Mexico	circa 1980	5,000,000
Offshore, W. Africa	1981	15,000,000
Onshore, Texas	1982	52,000,000
Onshore, Canada	1982	50,000,000
Onshore Indonesia	1984	78,000,000
Onshore S. Louisiana	1985	14,000,000
Offshore, Canada	1985	124,000,000
Onshore, Texas	1985	50,000,000
Offshore, Indonesia	1985	56,000,000
Offshore, South China Sea	1986	13,000,000
Onshore, Manchuria	1986	22,000,000
Offshore, Congo	1986	45,000,000
Offshore, Gulf of Mexico	1987	46,000,000
Onshore, N. America	1987	18,000,000
Offshore, Bay of Bengal	1987	25,000,000
Onshore, Kansas	1987	300,000
Onshore, S. Texas	1987	3,000,000
Offshore, S. America (ins'd loss)	1988	530,000,000†
Offshore Platform, North Sea	1988	1,360,000,000†
Offshore, Norwegian North Sea	1989	284,000,000
Onshore, S. Texas	1990	400,000
Offshore, Norwegian North Sea	1991	5,000,000
Onshore, Kuwait	1991	5,400,000,000
Onshore, Indonesia	1993	2,500,000
Offshore, Thailand	1992	1,200,000
Onshore, Indonesia	1993	2,200,000
Offshore, Thailand	1993	1,400,00
Onshore, Europe	1994	25,000,000
		$8,664,000,000

†Note: Includes the loss of the platform and redrill costs of the wells

††Note: Includes in no way is indicative of regional blowout control cost, it is merely a random list of wells shown here to illustrate variances in costs.

This action plan can be modified as necessary based upon actual well conditions, and should contain:

- 1.0 Definition of Scope
  - 1.1 Criteria for determining the level of severity of the problem
  - 1.2 Scenario classification to quantify the levels of severity
- 2.0 Development of the Blowout Contingency Plan
  - 2.1 Scenarios Plan
    - 2.1.1 Intervention techniques
    - 2.1.2 Kill techniques
  - 2.2 Organization structure
    - 2.2.1 Primary response team
    - 2.2.2 Project management Structure
  - 2.3 Resources and Logistics
    - 2.3.1 Immediate Response Plan
    - 2.3.2 Equipment and Personnel Mobilization Plan
      - a. Mobilization of staff
      - b. Locally available equipment
      - c. Foreign based equipment
  - 2.4 Interface to Other Groups
    - 2.4.1 Spill Cleanup
    - 2.4.2 Agency Groups: Coast Guard, EPA, etc.

The major components of the blowout contingency plan are described briefly in the following paragraphs.

Definition of Scope

Defining the scope of the operational plan is one of the most difficult tasks, because it requires forecasting the future. The scope of the project will have great ramifications and must be fairly accurate. The range of situations can vary from a minor event in an easily accessible unpopulated area, to a catastrophic worst case scenario in a populated or poorly accessible area. Keep in mind that the blowout contingency plan generally cannot encompass all areas, situations, and conditions effectively. If a significant difference in these factors exists, it would be better to develop individual plans tailored for each unique requirement. The following discussion outlines the various factors to be considered when defining the project's scope.

The initial consideration is the specification of a geographic region to be covered by the plan.

There have been attempts by operators to create a world-wide all encompassing plan. This may not be advisable as conditions vary widely and the plan will be too burdensome and complex to be useful. The geographical region should be carefully researched so a feasible workable plan is produced.

The potential downhole hazards of the specified region must be determined. These can include:

- Shallow gas
- Abnormal pressure and temperature gradients
- Abnormal fracture gradients
- Extensive reservoirs with high permeability and deliverability
- Hazardous fluids (H_2S, CO_2, etc.)
- Drilling hazards that are conductive to loss of control (lost circulation, etc.)

Note that the above are not necessarily high risk factors associated with the risk of a blowout, but merely factors that can make blowout control more difficult. Further consideration must be given to the proximity of the location to either populated and/or environmentally sensitive areas. The environment is becoming more important in today's attitude by the general public and most regulatory authorities and governmental agencies.

Criteria for Determining the Levels of Severity: The various types of losses occurring in a well control situation directly influence how decisions are made and must be addressed in the BCP. Following are the major types of losses:

1) Human life or injury
2) Equipment and facilities
3) Hydrocarbon reserves
4) Pollution control and clean up
5) Operational funds
6) Public image
7) Rights to drill and produce (license)

Scenario Classifications: Classification of blowouts into types and degree of severity will yield plans matched to the event and lead to more efficient operations. The goal of the blowout contingency plan must be to apply all necessary resources, but without overkill or waste. The Classification method is based on logistics required for control of the well. If the well control effort is well matched to the task at hand the men and equipment mobilized and used in the control are indicators of severity. Below is a generalized list of the types of classifications that may be necessary to describe possible well control scenarios:

Class V: A major event of the first order. Flows rates and pollution levels are very large. Impact on the environment and threat to life (human and nature) are significant and of great concern such as the presence of H_2S. A large spread of men and specialized and heavy duty equipment is necessary for the control effort. The total overall average daily cost for support of the well control effort exceeds $75,000 per day and control team staff and contractor support exceeds 200 people. An example would be an offshore event in an environmentally sensitive area where a relief well is required as well as an complex capping effort on a burning HTHP well.

Class IV: An event with significant flow rates and/or pollution levels. Impact on the environment and threat to life (human and nature) are of great concern. The spreads of men and specialized and heavy duty equipment is necessary for the control effort. The total overall average daily cost for support of the well control is between 50,000 - $75,000 per day and control team staff and contractor support is between 150 and 200 people. An example would be an onshore event in an environmentally sensitive area where a complex capping effort on a burning HTHP well.

Class III: An event with significant flow rates and/or pollution levels. Impact on the environment and threat to life (human and nature) are of great concern. The spreads of men and specialized and heavy duty equipment is necessary for the control effort. The total overall average daily cost for support of the well control is between 25,000 - $50,000 per day and control team staff and contractor support is between 100 and 150 people. An example would be an offshore event in an environmentally sensitive area where a routine capping effort on a blowout well.

Class II: An event with a blowout flow with or without pollution levels. Impact on the environment and threat to life (human and nature) are not presently of concern. The spread of men and specialized equipment is minor but necessary for the control effort. The total overall average daily cost for support of the well control is between 15,000 - $25,000 per day and control team staff and contractor support is between 50 and 100 people. An example would be an onshore event of a gas only flow where a routine capping effort is needed.

Class I: A minor event where the well may only be leaking and is not on fire. Minor pollution maybe occurring and hazards are minimal (provided the condition remains stable and other failures do not occur to worsen the situation and allow it to escalate to a more serious problem). The total overall average daily cost for support of the well control is less than 15,000 per day and control team staff and contractor support is less than 50 people. An example would be an onshore event of a gas only flow where wellhead repair is needed.

Development of the Contingency Plan

Possible Solutions: After defining the scope of the BCP, a plan of action may be developed to counter the problems presented by each scenario classification. Given the well conditions under each scenario, a specific approach may be established and the various methods of solving possible problems may be developed. There are four following basic approaches to a well control problem:

1) Surface intervention and pump to kill
2) Relief well and pump to kill
3) Combination of relief well and wellhead intervention
4) Unique (infrequent) solutions

Once the severity of the well control problem has been determined (by reservoir models, or by judgment and experience), a kill plan can be formulated. The material, services, and logistics required can then be determined. This section does not focus on the logistic and engineering requirements, but offers an overview of the planning necessary to have a proper BCP.

Given the severity of an event, engineering of the control effort can proceed. One can assume that a certain Class of blowout occurs, and go about planning the options that are available and feasible in that condition. The first step is to determine what type of kill is then possible. For example, a problem on a well in deep water or where the platform was destroyed would generally preclude the possibility of surface intervention, leaving the relief well scenario the only suitable method.

Surface Intervention Techniques: If intervention is to be accomplished or attempted, many specific details are needed. These problems generally are subcontracted to specialized companies who offer a range of capabilities and services in surface intervention techniques. However, the operator should become acquainted with these techniques and the logistics required to implement them. An incomplete list of surface intervention techniques are listed below:

1) Fire suppression and extinguishing methods (water, chemical, explosives, etc.)
2) Severing techniques for casings, wellheads, and structural members (abrasive, water jets, sawing, die cutters, explosives, etc.)
3) Wellhead and tree removal and replacement in pressurized situations (commonly referred to as capping operations, tree snubbing, etc.)
4) Diversion of large flows containing abrasive and corrosive fluids
5) Freezing techniques and hot tapping
6) Snubbing operations

Relief Well Intervention: Implementation of a relief well as a well control technique basically involves establishing direct communication with the problem well by directional drilling of a hole to a specific downhole location in very close proximity to the problem well. Once communication is established, it should then be possible to pump the well dead. Figure 1 outlines the major decision process required for a relief well planning.

Combination Surface / Relief Well Intervention: Under certain well conditions, it is conceivable that both intervention methods would be required to kill a well. This situation would most likely occur in the most severe situations.

Unique Solution: Occasionally, more unconventional techniques may be suitable. The extent of these methods may challenge the imagination or be as simple as allowing the well to die or bridge off on its own.

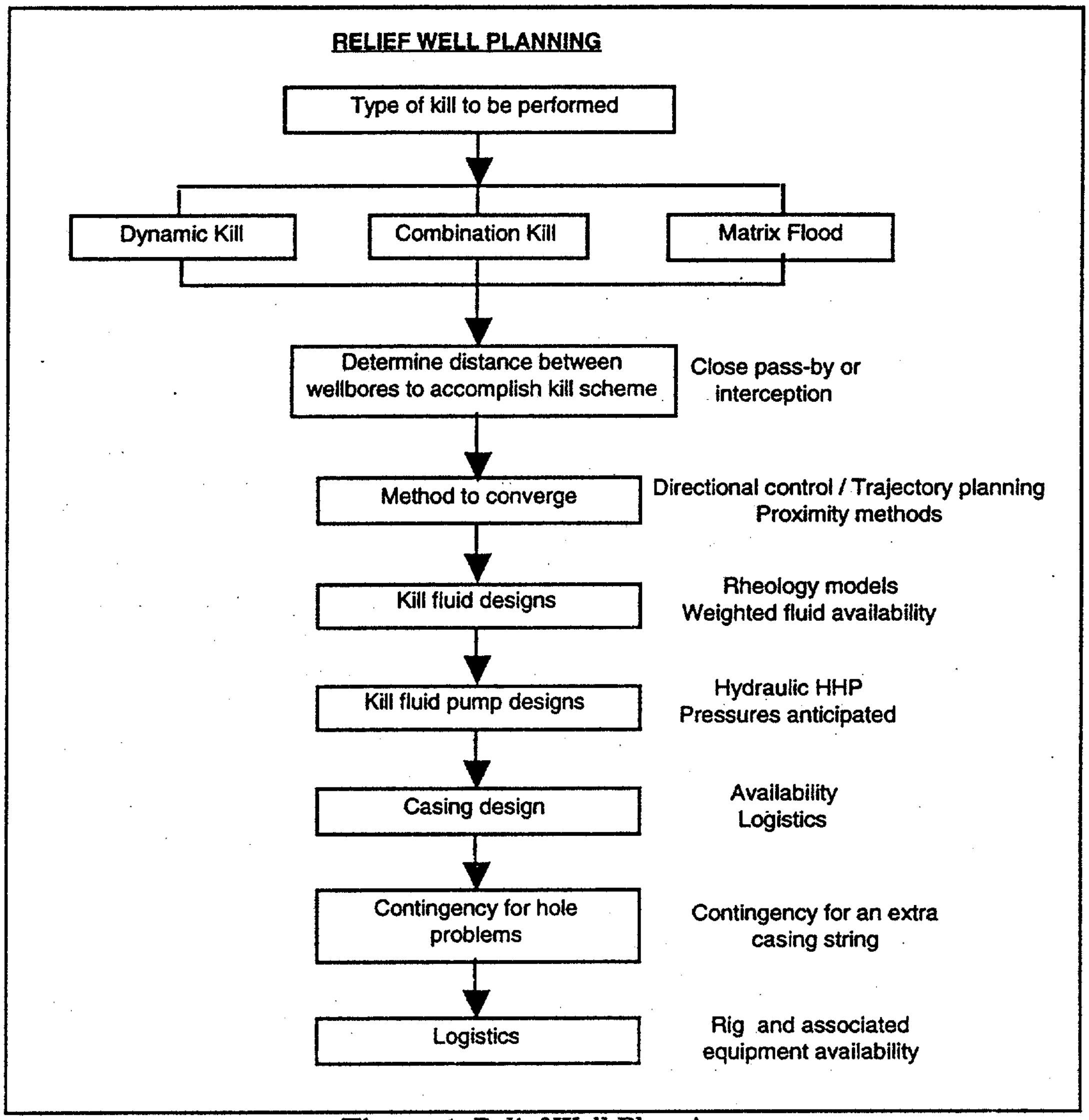

Figure 1 Relief Well Planning

After, and perhaps during, the intervention process, a kill operation is normally undertaken. The type of kill must be carefully chosen to prevent further damage and risks. There have been cases where intervention and or kill operations caused the problem to worsen.

For example, an offshore project in Indonesia in 1985 began as a single blowout of a drilling well on a 12-well platform. An intervention was undertaken where a well control company recommended the shut-in of the well using the existing drilling BOP's. Upon shut-in, the well breached the casing and blew out some short distance below the mudline. In less than 14 hours, a crater opened up under the platform 90 meters in diameter and over 150 meters deep. The result was that the platform collapsed in the crater placing the other wells in jeopardy. Clearly, the surface intervention technique caused the platform to collapse and exposed the operator to additional losses. Had snubbing or a different pumping job been used instead, the well might have been controlled without loss of the platform. The operation to drill relief wells costs over $50 million USD and took 14 months to accomplish. The snubbing technique would have taken less time and would have been less costly.

In another case, offshore Mexico, a bullhead technique was attempted. This resulted in the casing bursting just below the subsea BOP's. Prior to bursting the casing, the well was contained, but afterwards, a catastrophic oil spill resulted. Even the famous Adair "Sombrero" proved to be ineffective in controlling the oil pollution. This again shows that careful planning and evaluation of the technique *must* be undertaken.

In yet another case, a surface intervention from a relief well went astray. The problem was a shallow gas blowout, offshore West Africa. The relief well had killed the well using a dynamic technique with sea water as a kill fluid. The pumps were shut down due to darkness and the well blew out again. The next step undertaken was a massive pump job using a heavy brine. This job resulted in disaster. The open hole section in the relief well fractured back to the surface, and both the platform and the jack-up rig were swallowed in a crater. This occurred in 1978 and as of the date of this report the well is still blowing a substantial amount of gas.

These case histories illustrate that care must be taken in choosing and implementing the kill operation. The type of kill operation must be fully investigated to assure the operator that it will work and will not expose the operator to additional risks. This report cannot address all of the kill techniques due a limit in the scope of work. In the following paragraphs are lists of most of the techniques available, with a brief description of how each technique works in control of a blowing well.

1) Shut-in at the surface after capping the flow. This technique uses wellhead equipment to stop the flow and contain any pressure that is exerted at the surface. The downhole conditions and equipment must be sufficient to contain the pressure and "water hammer" effects of suddenly closing in the well. The final kill is then handled in much the same way a production well is killed.

2) Volumetric control operations. Volumetric control can be accomplished given that circulation is not possible and the well can withstand the pressure and stress of being shut in at the surface. This technique involves the pumping in of fluid from the surface, bleeding back excess pressure after waiting for the wellbore fluids and the kill fluid pumped in to exchange places. This method can also be used to handle gas migration while maintaining constant bottomhole pressure.

3) Snub into the well with kill strings or equipment. Snubbing technique can be successful in entering the well either in a pressurized or flowing condition. In most cases where snubbing has been used in post-blowout work, a kill string is run to a sufficient depth to kill the well by pumping fluids. In some rare and limited cases, packers have been used to stop flows below casing leaks.

4) Divert the flow. This technique handles the flow at the wellhead and diverts it away through a vent line. It can give access to the wellhead so that other techniques, such as snubbing can be implemented. It can be used to produce the flow to a pipeline or production facility.

5) Dynamic kill. The dynamic kill utilizes both hydrostatic and frictional pressure to overcome the reservoir pressure in the producing zone. It usually requires massive pump rates and careful coordination. It is usually performed from a relief well and sometimes from a string in the blowing well.

6) Minimum kill techniques. Minimum kill technique is a pumping method that is utilized at the moment that a flowing or blowing well is closed in. The pump rates, types of fluids, and density of fluids pumped during the kill operation are carefully planned so that minimum pressure is exerted downhole during the procedure. For example, the friction and hydrostatic losses can be carefully planned so that the well is killed while simultaneously maintaining the minimum pressure against the wellbore. This can be useful in situations where the integrity of the tubulars or wellhead equipment is unknown or in question.

7) Momentum kill techniques. Momentum kill technique is the creation of a fluid plug in a downward direction that overcomes the upward motion of the blowout. It is a top kill operation that does not require re-entry into the well with a work string and can be done from the surface. However, it may require exotic fluids and very high pump rates. Knowledge

of the flow rate and consistency of the fluid must be known to plan the job. It has the tendency to create very high hydrostatic pressures and friction losses and must be studied carefully to insure that the downhole equipment can withstand the stresses.

A basic understanding of the above techniques must be known before the BCP can be created. From these tools, a basic plan for the control of any class well can be mapped out. Specialized equipment is necessary and should be either purchased and placed on standby, or sourced in such a way that it can be obtained in a reasonable length of time.

Organization Structure

Primary Response Team: Recall that the first step will be to choose the severity of the problem to be dealt with. The severity of the problem will mandate a staff and effort fitting the task. Minor events will require small staffs while major tasks will require large staffs. The control of a major staff effort will be quite difficult. Project teams are best suited to handle difficult tasks. Some operators have designated an internal primary response team consisting of staff members from several disciplines within the organization. If an event occurs, the primary response team is mobilized to access the severity of the situation and to take appropriate action in order to control the well.

A common mistake made by operators in creation of blowout response teams is to burden the in-place operation staff with both the wild well responsibility and normal duties. This can put undue stress on the group. Of course, the most efficient means of controlling any project is to encourage dedication to the task. People cannot devote full attention to two separate tasks.

The creation of a management group whose sole task is to manage the control project is good operational practice. Small teams are usually more effective than large teams. A few good, qualified people are better than a large staff of inexperienced people. A study of successful businesses revealed that "teams that consist of volunteers for a task of limited duration, and are set in their goals are usually found to be more productive. The task force group found to highly effective also has the following characteristics:"[3]

- Limited team members (10 or less)
- Reporting level and seniority are proportional to the importance of what is being done.
- Duration of team existence is limited (short)
- Membership is voluntary
- Team is created rapidly and only when needed
- Follow up is swift and decisive
- Documentation is informal (limited)

The most important factor is that the team has an action bias. "Action bias is willingness to try things out ..."[4] Sometimes "chaotic action is preferable to orderly inaction"[5].

The primary response team must make the following major decision soon after a well control event occurs:

1) Evacuation of the site and/or facility to reduce the risk to personnel. This must follow a predetermined plan and authority to implement should always be on site.
2) Evaluation of the situation. (Is a simple and quick solution available? What are the risks? How quickly will the situation deteriorate? Time dependence for severity/deterioration).
3) What is the level of the control effort? (Class I, II, III, etc.)
4) What team members are to be assigned and/or mobilized?
5) What experts are required to access the control situation?

Once the initial assessment is completed, an operational plan must be implemented. The operational plan should have short range and long range goals. The short range goals are:

1) Safety of personnel and the general population
2) Evaluation of the situation on a real-time basis
3) Determination of the rate of deterioration for the situation
4) Immediate plan of action for control, if possible

5) Pollution control to minimize the environmental impact

6) Dealing with hazardous materials (H_2S, etc.)

The long range goals are focused on an ultimate solution, given that a short term solution is not feasible or probable. The object of these goals is to help direct the control effort in the most effective and cost efficient manner. Prudent action will dictate that a careful evaluation of all feasible methods be made and only the most suitable be retained for further consideration. Depending upon the severity of well conditions, such as the threat to human life and possibility of pollution, the list of methods for implementation should be reduced to a single method except for the most severe case. In severe cases, the maximum of three methods should be considered.

A primary control method should then be designated and a concentrated effort should be devoted to that method.

In the case of a severe problem, secondary methods may be developed and possibly pursued with the understanding they do not deter progress of the primary method. Should the primary method fail or well condition evolve to the point where a secondary option becomes the method of choice, the concentration of effort should be shifted to allow the earliest possible control of the well.

The long range goals of the control effort should include:

1) Safety of personnel and population
2) Control of the well or wells
3) Recovery or permanent abandonment of the well(s)
4) Handling of hazardous materials (H_2S, etc.)
5) Minimizing pollution to reduce environmental impact
6) Maximizing the effectiveness of the kill operation without excessive costs
7) Minimizing cost of control
8) Minimizing reserve losses
9) Minimizing damages to public image

<u>Project Management Overview</u> The well control effort is best managed on a project management basis. This approach is designed to plan, organize, staff, direct and control the effort. There will be varying roles between the disciplines like reservoir engineering, drilling engineering, logistics and the project management staff. The roles of each asset group must be determined and authority established. The role and authority of the project manager must be firmly established. Sufficient authority and responsibility must be entrusted to the project management group and project manager to accomplish the task at hand.

The organizational structure must be determined, including lines of authority, job descriptions, and responsibilities. Lines of communication must also be established. Figure 2 illustrates the general responsibilities. It is vital to the overall effectiveness of the team for all to be well informed of:

- Current situation
- Major decisions made by the management team
- Legal and governmental implications
- Public relations
- Goals established by the management team

For the team to be effective, each team member must be well informed of his responsibility and authority. Without these, the members will be ineffective. To control the project, a comprehensive decision tree is very helpful, and in fact it is mandatory.

Risk models are also useful in assisting with the decision process. A decision tree can be too comprehensive or it can include events that have a low probability of occurring. Above all, the decision tree must be a practical model for likely and probable events. In no way can one accurately predict all scenarios, but it is possible to predict reasonable and probable events.

The scope of the project will need to be locked in at the earliest possible moment. The project team is then assigned and given the task to control the well. The project is then put into action. Usually a kick-off meeting is held to initiate and inaugurate the beginning of the effort.

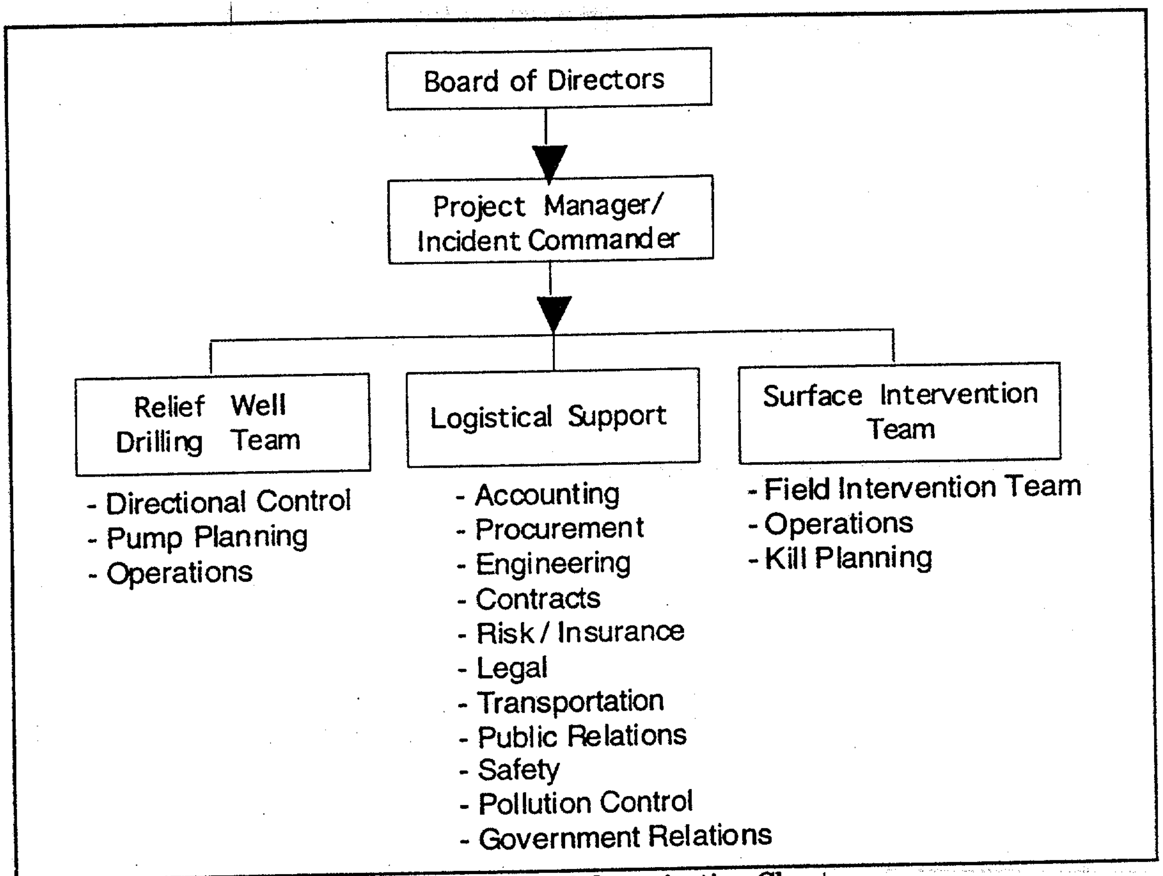

Figure 2 Generalized Organization Chart

The project management approach to the task will have components including:

1. Development of the Work Plan
   - 1.1 Work breakdown structure
   - 1.2 Organizational breakdown structure
   - 1.3 Creation of a Macro Project Schedule
   - 1.4 Establishing who does what, when, where and how much
   - 1.5 Communicating the plan
2. Project Planning
   - 2.1 Strategies to control the overall project
   - 2.2 Development of realistic schedules
   - 2.3 Responsibilities of operators, contractors, service companies
   - 2.4 Development of CPM model with network diagrams
   - 2.5 Considerations of time, cost, and work in place
3. Design Coordination
   - 3.1 Man-hour schedule
   - 3.2 Distribution of documents
   - 3.3 Drawing and procedural index
   - 3.4 Equipment index
   - 3.5 Authority / Responsibility check lists
4. Operational Phase
   - 4.1 Bid packages
   - 4.2 Bid evaluations
   - 4.3 Service companies & contractors relations
   - 4.4 Correspondence and reports
5. Tracking the project while it is in the operational phase
   - 5.1 Time schedules
   - 5.2 Cost analysis
   - 5.3 Linking time, cost, and work in place
   - 5.4 Who is responsible for what
6. Project Completion
   - 6.1 Final inspection and assurance of completion
   - 6.2 Stopping work / demobilization
   - 6.3 Disposition of material and re-usable equipment
   - 6.4 As-built drawings and documentation of the events

7. Simultaneous Task not directly associated with the actual kill operations
   7.1 Liaison with regulatory bodies (NPD, police, etc.)
   7.2 Deal with press/public relations
   7.3 Deal with outside operators and partners
   7.4 Deal with legal problems & legal actions
   7.5 Deal with insurance matters

performed a good job of operation they surely won't have blowout experience). It is therefore advisable to bring in personnel who have had past experience with blowout and well control companies, and should be sourced before the event occurs.

Another source of personnel will be from the service company sector. Some service companies will be able to provide staff familiar with the types of problems to be encountered. They may also be able to assist by providing

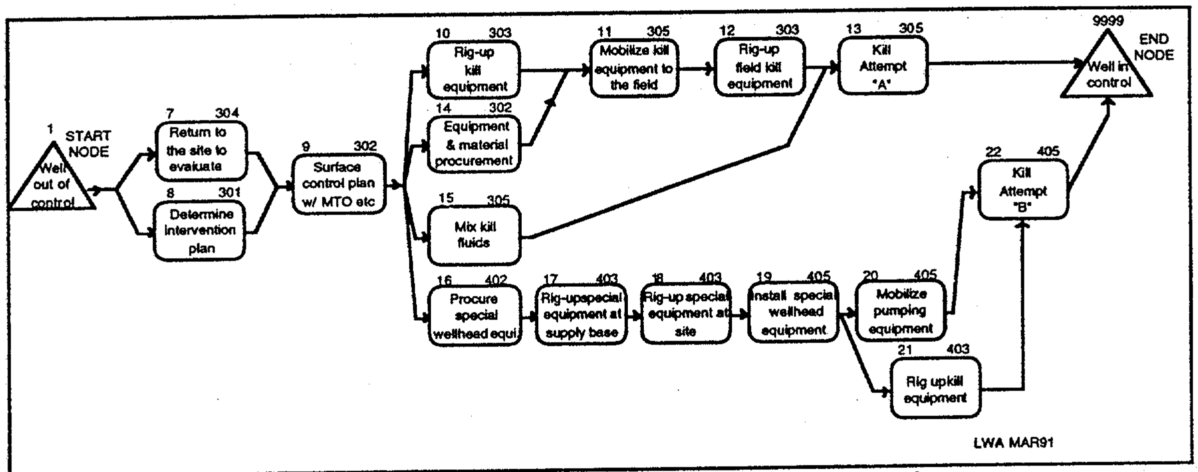

Figure 3 Simplified CPM Network For A Blowout Project

The project should be conducted with an early conclusion as a major goal. Again the wisdom of Sun Tzu[2]. "we have heard of the stupid haste in war, cleverness has never been associated with long delays. In all history, there is no instance of a country having benefited from prolonged warfare." The key is to not be reckless and introduce additional risk at the expense of safety or in the hopes of reducing the overall cost or improvement of schedule.

<u>Resources:</u> Numerous resources are available for the control of wild wells. They are classified as personnel and equipment. Personnel can come from the operational staff, specialized contract companies, and services companies. No one will understand the local parameters better than the operational staff currently in place, so it is prudent to assign part of the control team from the current operational staff.

There are many schools of thought concerning who is to be in ultimate control of a blowout. Some will support the idea that local management is best suited. While this group does possess the knowledge inherent to the locality, they may not be experienced in the control of a blowout (in fact, if they have

engineering and technical expertise in conjunction with their services.

Equipment will be necessary to control the well. It can be sourced from company owned stores, borrowed or leased from other operators, purchased directly, or contracted from service companies. In most cases the equipment necessary for the control effort is essentially common oilfield equipment, such as pumps, valves and etc. In some cases, unique and rare equipment will be necessary, as in the case of

pump manifolds, high pressure risers, re-entry BOP equipment, hydraulic set wellheads and etc. To further complicate matters, odd, specialized and typically non-oilfield items may be necessary, such as explosives, hydro-cutting tools, etc. It is best if sources for each piece of equipment can be identified and pricing structures negotiated as a component of the contingency plan.

Experience has shown that pricing is more reasonable if determined beforehand, than when sourced in an emergency purchase basis.

Special materials also may be required which are generally out of the scope of normal operations. For example, a heavy brine (3.5+ SPG) may be necessary. Sources and detailed logistics for special materials are needed in order to run a well managed and difficult control project.

There are useful project management techniques available. One is CPM (Critical Path Modeling) and others range from the decision and risk models to resource and cost tracking models. These models will assist the team in the implementation of the project. CPM is particularly useful in scheduling and overall tracking of progress.

Figure 3 illustrates a simplified CPM network for a blowout project. CPM techniques are mentioned in this report but the scope of the report does not allow detailed description of the method. Fig 4 is a $275+ MM Class V type event where advanced planning could have had dramatic impacts by reducting mobilization and operational time. Decision trees are very useful in planning a complex project. These can be most useful when large groups of people need to be coordinated with the task. A typical capping operation decision tree is shown in Figure 5.

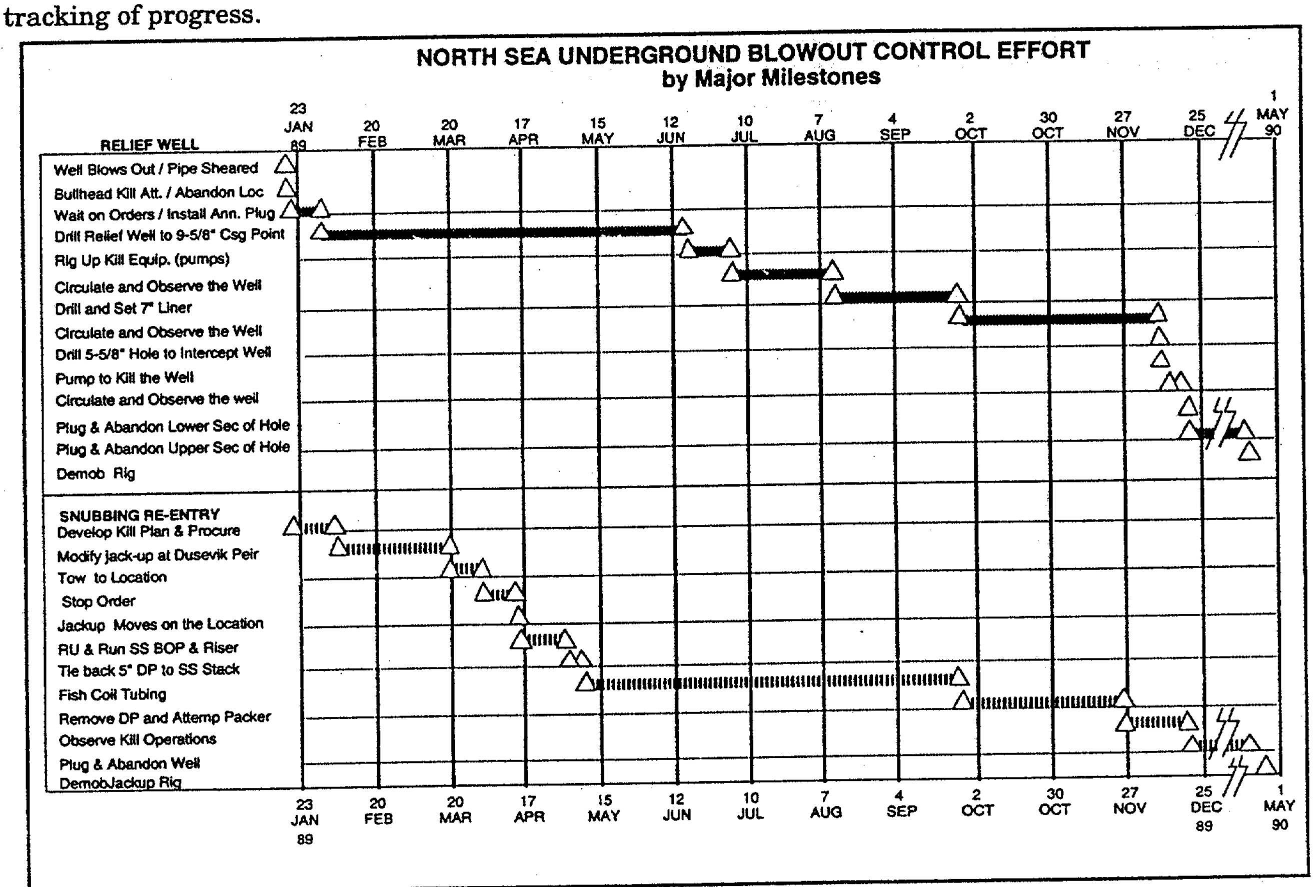

Figure 4 Milestone chart of an actual North Sea underground blowout"

Properly done, it will enable the managers to predict with reasonable accuracy of such things as the cost and timing of major events. It is also a means to force a certain amount of planning to be done.

Tracking models are useful in reporting and analyzing costs. They are similar to CPM models and should correlate to the CPM model being used in some ways.

They have uses in reporting the cost and progress to management, partners, governments, and insurance representatives both during and after the task.

Decision trees "force" the creator to think through all the contingencies that may occur while combating a well control problem.

Conclusions

Emergency preparedness is the key to success in a well control project. Although it is commonly thought that each blowout is unique, and all techniques required are one-of-a-kind or applicable only to that event, many of the techniques, types of equipment, and range of services are common to blowouts in general.

One can, therefore, plan and develop a BCP before the event occurs. If this is done, the control effort can be a fast-track project, minimizing the loss and risk to the operator.

Acknowledgments

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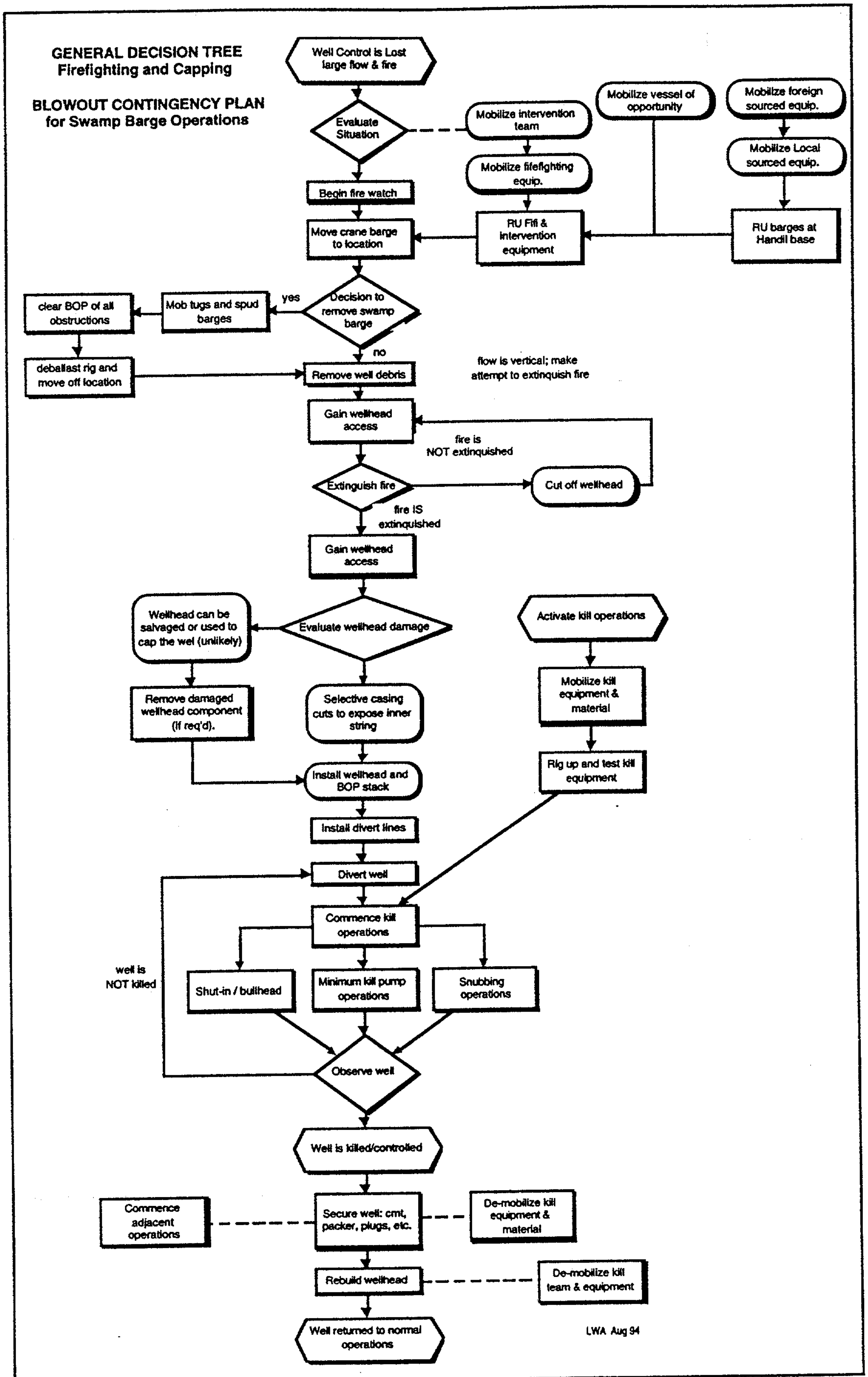

Figure 5 Generalized Capping Decision Tree

Industry Input and Operational Considerations

NOTES:

NOTES:

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JOINT INDUSTRY PROPOSAL -- DEA # 89

Improved Contingency Planning for Flow after Cementing of Surface Casing

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Background

Current well control practice for bottom-supported marine rigs usually calls for shutting in the well when a kick is detected if sufficient casing has been set to keep any flow underground. Even if high shut-in pressures are seen, an underground blowout is preferred over a surface blowout. On the other hand, an operator on a bottom-supported vessel will put the well on a diverter if he believes that the casing is not set deep enough to keep the underground flow outside the casing from breaking through the sediments to the surface. Once the flow reaches the surface, craters are sometimes formed which can lead to loss of the rig and associated structures. Cratering also increases the difficulty and time required to kill the blowout.

A particularly difficult well control problem sometimes arises when flow or pressure build-up is noted on the conductor/surface-casing annulus just after cementing operations. Selecting the best procedure for a given well situation in not a well defined process and company policy is usually based on highly generalized "rules-of-thumb." Some operators currently let the unset cement unload on a diverter, others elect to keep the well shut-in, and others will bull-head mud down the conductor-surface casing annulus. There continues to be periodic accidents, spills, and economic losses related to this problem. MMS has recently expressed concern that improvements are needed in this area. This joint industry proposal deals with the development of improved techniques for preventing this problem and developing improved contingency plans for a given well situation when the problem occurs.

A project currently in progress has identified the following four main sediment failure mechanisms that can lead to cratering:

- borehole and fracture erosion,
- sediment liquefaction,
- piping, and
- caving due to borehole failure and sand production.

While all of these mechanisms contribute to crater formation, caving due to sand production appears to be the most important mechanism leading to the formation of large craters that result in loss of a platform or jackup rig. When borehole pressure is loss, shallow water sands begin to produce and borehole enlargement in the sand sections results from unconsolidated sand being carried out of the well with the produced water (Figure 1). In one documented case occurring on land, produced sand was spread over 100 acres and was 40 inches thick near the edge of the crater. Borehole enlargement in the sand and silt sections lead to collapse of the overlying clays into the enlarged hole. Once the overlying clay has slumped into the open section, it too can be more easily washed from the hole.

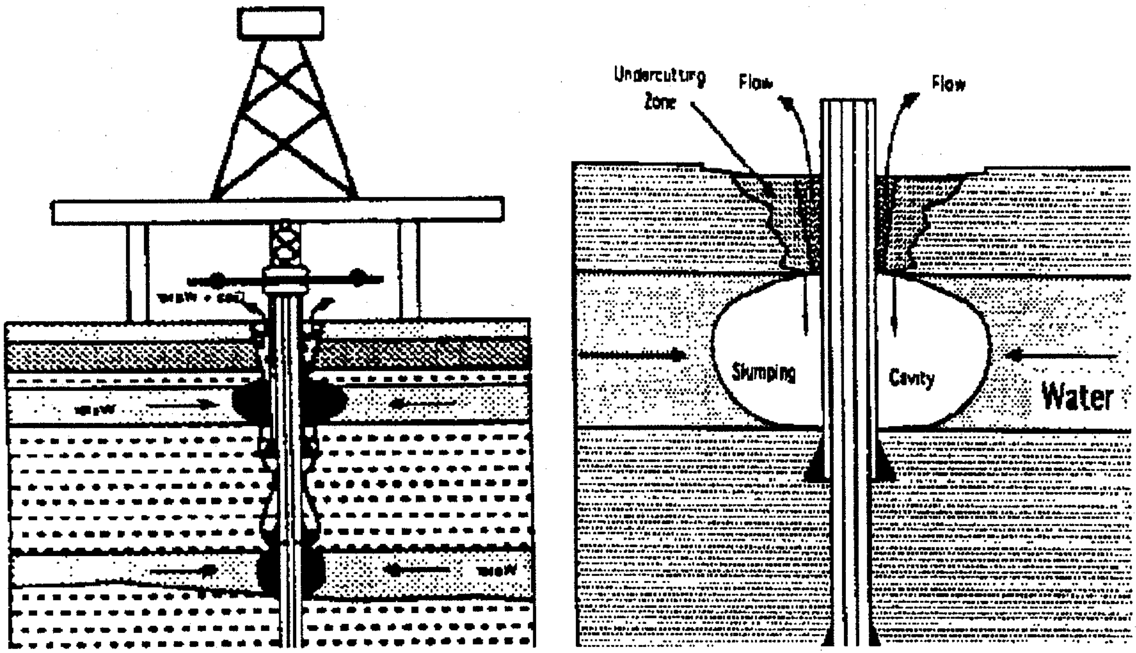

Figure 1 -- Caving due to Sand Production can lead to Crater Formation.

Examination of a few case histories has shown evidence that cratering can develop below conductor casing having about 500 feet of penetration below the mudline, even when the well is not shut-in. Release of the surface pressure promotes flow from the exposed water sands which triggers the borehole enlargement mechanism discussed above. Another case history involving flow after cementing of surface casing indicated that significant surface pressures can be held on conductor casing without the development of a large crater.

Many operators now shut-in kicks taken below conductor casing on floating vessels, but not on bottom supported rigs. This preliminary study has indicated that at least in some cases, it may also be best to shut-in a kick taken below conductor casing on bottom supported rigs. It is believed that a more in depth study of available case histories is in order to determine if risks of cratering could be reduced by an improved contingency planning procedure for the kicks taken below conductor casing. A first step in this direction would be a study of kicks taken while cementing surface casing. It is believed that there should be more examples where the operator shut-in the well for this situation. Other cases of interest would be kicks taken below conductor casing that were shut-in during floating drilling operations. However, conductor casing is often set deeper for floating drilling operations than for bottom supported rigs.

Scope of Work:

The work will involve:

- Analysis and documentation of available data on case histories occurring in various offshore areas of the world for which data are available during the past 20 years.

- Survey and documentation of current technology for preventing gas flow after cementing surface casing in offshore operations.

- Survey and documentation of current operator policy and procedures for handling gas flow after cementing surface casing in offshore operations.

- Development of computer model for estimating the risk of sediment failure and cratering for a given shut-in pressure, casing plan, and sedimentary sequence if the conductor-surface-casing annulus is maintained closed and not put on a diverter.

- Enlargement of the LSU overburden density and leak-off test database for marine sediments for better prediction of fracture initiation pressures in shallow sediments. Cement densities circulated to the surface inside conductor casing will also be used in the database as a sediment strength indicator.

Technology Transfer:

Technology transfer to participating members would be through annual reports, annual workshops at the LSU Research and Technology Transfer Laboratory, and through an INTERNET Well Control Client Server maintained in the LSU Petroleum Engineering Department. Participating members would be able to download software, database, and case history files not available to the general public.

Deliverables:

The deliverables provided from this project will include an oral and written report given at an annual workshop. This workshop will be coordinated with the LSU / MMS Well Control Research Project. Thus, by attending the workshop, the participant will be able to keep abreast of progress made on all of the well control related research being conducted at LSU. The annual report will contain documentation of all of the case histories and surveys conducted during the year and all computer files developed as part of this project.

Much of the project work will be done by Seniors and Graduate Students in Petroleum Engineering. A fringe benefit of this project will be the availability of more knowledgeable graduates for work in drilling and producing operations.

Participation Costs:

The annual cost per participant would be $10,000 per year and it is envisioned that a simple letter of agreement would accompany each annual payment. The commitment would be for a one year period, and continued support would be decided on an annual basis. Each participant would direct his support towards one of the tasks being conducted during the year. The tasks anticipated for the first year of the study include (1) review and documentation of case histories of flow after cementing surface casing, (2) review and summary of the literature and of operator practice concerning the prevention of flow after cementing, and (3) establishing an internet system and file format for development of a shallow formation strength database.

SUMMARY AND CONCLUSIONS

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Workshop Evaluation Form, Day 1

Session	Evaluation Excellent	of Good	Workshop OK	Activity Poor	Comments
Review of 15 Known Shallow Gas Incidents					
Current Regulatory Requirements					
Technical Discussion of Fluid Migration after Cementing					
Contingency Planning for Well Control Operations					
Discussion of WOC Criteria					
Discussion of Operational Considerations					
LSU Project on Contingency Plans for Handling Flow after Cementing Surface Casing					
Overall Day 1 Workshop on Shallow Gas Migration after Cementing					
Site Visit to Research Facility					

General Comments and Suggestions:

Introduction

by Adam T. Bourgoyne, Jr., LSU

LSU, with the support of the petroleum industry and the US Minerals Management Service, has maintained an on-going research program in blowout prevention for more than a decade. The initial emphasis was on deep-water well control procedures. In January, 1981, a research well facility was completed to provide a near full scale system for experimentally studying well control procedures that could be applied in a deep water environment. The facility was centered around a 6,000 ft well complete with subsurface equipment which allowed essentially full scale modeling of the flow geometry present on a floating vessel operating in 3,000 ft (1000 m) of water. Extensive new surface equipment also was installed to allow highly instrumented well-control experiments and training exercises to be conducted.

Funding for the new research and training well facility was obtained through the combined support of a consortium of 53 companies in the petroleum and construction industries. The project was given a big boost when Goldking Production Company, after drilling a 10,000-ft, $670,000 dry hole on the LSU campus agreed to donate the well to LSU.

Thirteen major oil companies contributed special grants totaling $200,000 for the needed well completion work and surface facilities. Grants of equipment and services valued at $1,200,000 were provided by 40 service companies. In addition, approximately $200,000 of the well completion and site preparation costs were provided as part of a research contract sponsored by the Minerals Management Service.

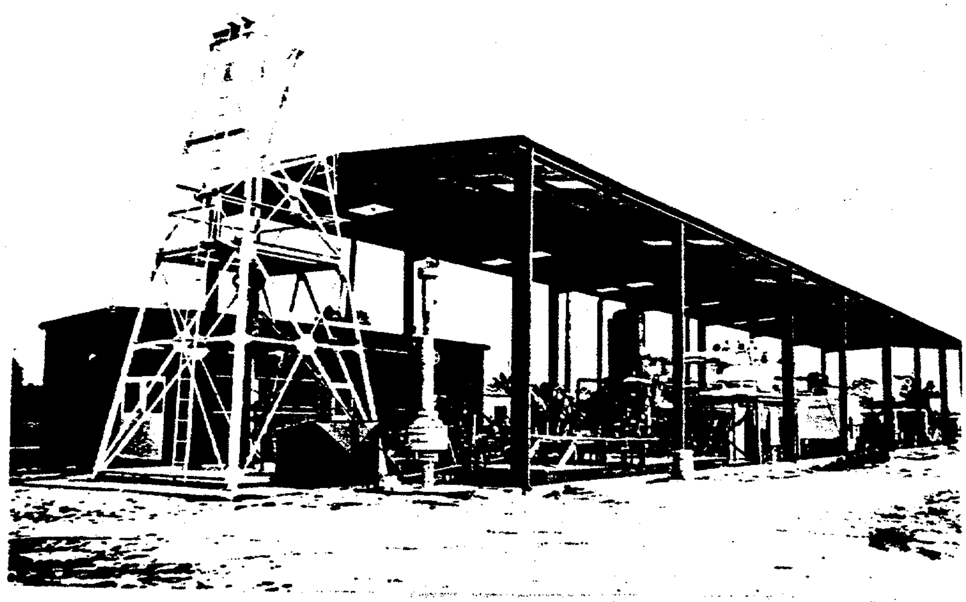

Figure 1 - Photograph of research well facility when it became operational in 1981.

A 1981 photograph of the research facility is shown in Figure 1. The main features of the facility included:

- A 6,000 ft well,
- A choke manifold containing four 15,000-psi adjustable drilling chokes,

- A 250-hp triplex pump,
- Two mud tanks with a combined capacity of 550 bbl,
- A high capacity mud-gas separator,
- Three degassers of varying designs,
- A mud mixing system,
- An instrumentation and control house, and
- A classroom building.

Figures 2 shows some of the instrumentation in the control house.

The subsurface configuration of tubulars in the well was chosen so the well would exhibit the same hydraulic behavior during pressure control operations as a well being drilled from a floating drilling vessel in 3000 ft of water.

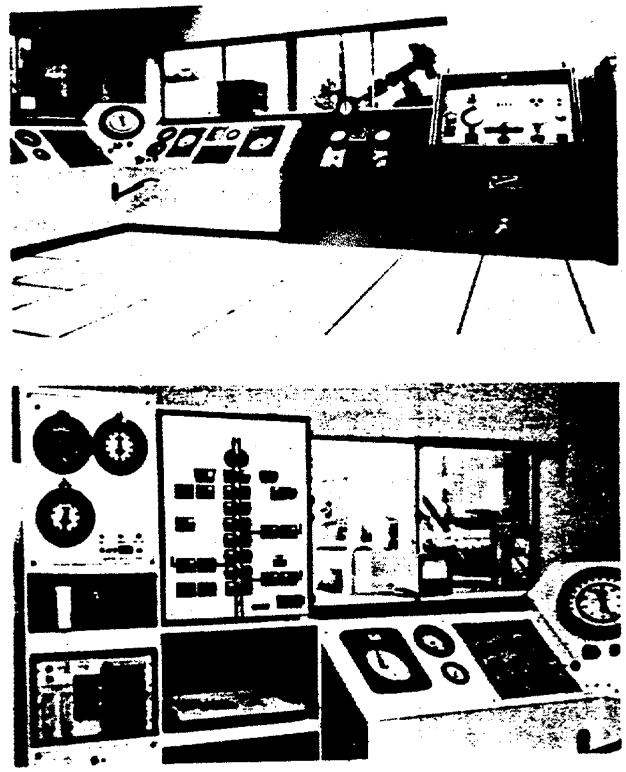

Figure 2 - Instrumentation and control panel.

The blowout prevention problem on a floating drilling vessel in deep water is complicated by the location of the blowout preventer (BOP) stack at the seafloor rather than at the surface and the use of multiple high pressure subsea flowlines from the BOP to the surface. In shallow water, the effect of the subsea flowlines is small and the well control system responds much like well control equipment on a land rig or a bottom supported marine rig. However, in very deep-water wells further offshore, the consequences of this special flow geometry become much more pronounced.

The effect of locating the BOP at the seafloor was modeled in the research well using a Baker packer and a Baker triple parallel flow tube as shown in Figure 3. Subsea flowlines connecting the simulated BOP to the surface were modeled using 2.375-in. tubing. A subsea wing valve on one flowline is modeled using a Hydril surface-controlled subsurface safety valve. The simulated wing valve allowed experiments and training exercises to be conducted using only one flow line, with the other line isolated from the system, as is often the case in well control operations on floating drilling vessels.

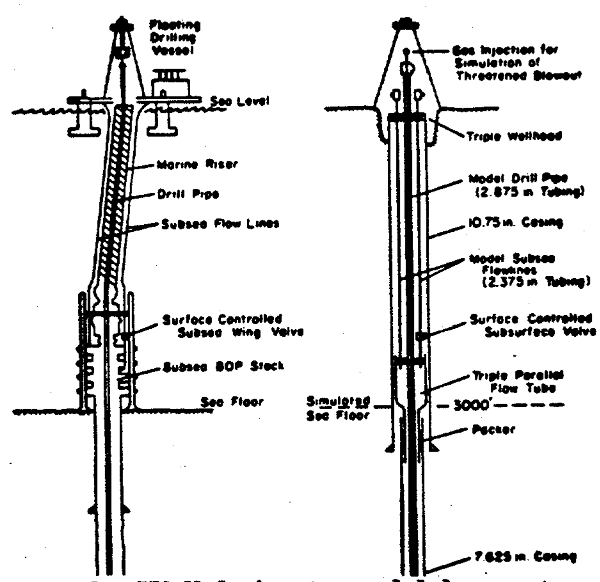

Figure 3 - Well design to model deepwater well control operations.

Drill pipe was simulated using 6,000 ft of 2.875-in. tubing. Nitrogen gas was injected into the bottom of the well at 6000 ft to simulate influx from a high pressure gas formation. The nitrogen was injected into the well through 6,100 ft of 1.315-in. tubing, which was placed inside the 2.875-in. tubing.

A Sperry Sun pressure transmission system was placed at the bottom of the nitrogen injection line to allow continuous surface monitoring of the bottom-hole pressure during simulated well control operations. The pressure signal was transmitted through 0.125-in. capillary tubing which was strapped to the 1.315-in. gas injection tubing. A check valve located at the bottom of the gas injection line allows this line to be isolated from the system after the gas kick is placed in the well.

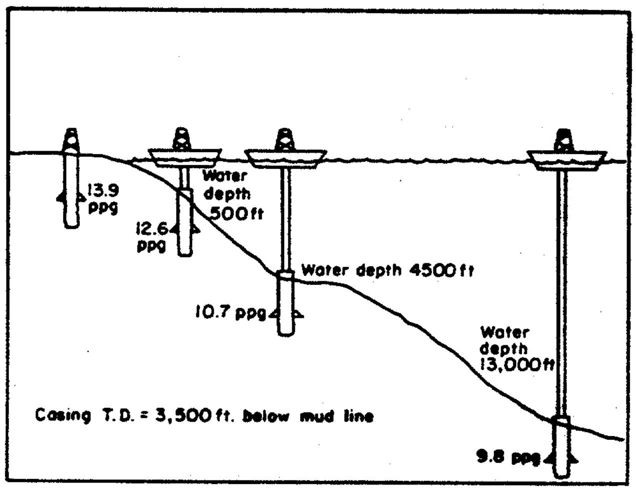

Figure 4 - Effect of water depth on fracture gradient for 3500 ft penetration.

Like many other aspects of drilling operations, the problem of blowout prevention increases in complexity for floating drilling vessels operating in deep water. Several special well control problems stem from greatly reduced fracture gradients and the use of long subsea choke and kill lines. Figure 4 shows the approximate effect of water depth on fracture gradients below surface casing, expressed in terms of the maximum mud density that can be sustained during normal drilling operations. Note that the maximum mud density that can be used with casing penetrating 3,500 ft (1067 m) into the sediments decreases from about 13.9 lb/gal (1666 kg/m3) on land to about 9.8 lb/gal in 13,000 ft (3962 m) of water. These lower fracture gradients result primarily because the open hole must support a column of drilling fluid that extends far above the mud line to the rig floor. This additional column weight is only partially offset by the seawater. An additional contributing factor is the relatively low bulk density of unconsolidated shallow marine sediments.

Abnormal formation pressure is often encountered at more shallow depths in deep water areas of the Gulf of Mexico. The combination of abnormal formation pore pressure and low fracture resistance results in a need for a large number of casing strings to maintain even a small safety margin between the choke pressure required for well control in the event of a threatened blowout and the choke pressure that would cause formation fracture. Thus, it is often important to be able to maintain pressures close to the target pressure during well control operations. However, manual choke operation is often far from infallible, especially for the complex geometry present in deep water.

Shown in Figure 5 is an example kick simulation in the research well for a 21 bbl gas kick pumped out by industry field personnel during a training exercise. This example illustrates a problem that can occur when the frictional pressure loss in the chokeline is almost as large as the shut-in casing pressure. On completion of pump startup, the required backpressure on the annulus is provided almost entirely by the frictional loss in the choke line. Thus, the choke can be opened far beyond the normal operating range with only a small response in drillpipe pressure. If the choke operator is caught with the choke in nearly a full open position when gas enters the subsea choke line, it is extremely difficult to close the choke quickly enough without closing it too much. Note that in this example, a +400-psi (2758-kPa) error in bottom hole pressure occurred while gas was in the subsea choke line.

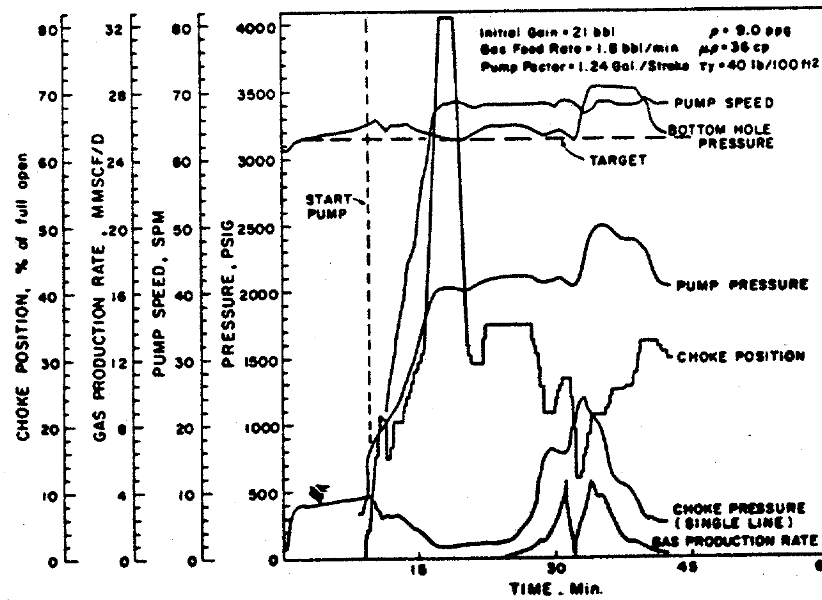

Figure 5 - Example data collected for well control operations in deep water.

A number of common situations were experimentally studied that can lead to errors on the part of the choke operator as large as the example shown in Figure 5. However, it was found that the demands placed on the choke operator were not as great as previously predicted by computer simulations of well-control operations. Nevertheless, considerable hands-on practice may be required for the operator to master the needed special procedures.

A number of new well control procedures developed for the special geometry and low kick tolerance of deep water exploration were experimentally studied under Minerals Management Service sponsorship. These included:

- special shut-in procedures when an influx of formation fluid into the well is detected,
- special procedures for handling gas migration in a closed well,
- special procedures for starting the circulation of a closed well containing formation fluids, and
- special procedures for handling rapid gas expansion in the subsea flowlines connecting the blowout prevention equipment at the seafloor with the surface equipment on the floating drilling vessel.
- special procedures for handling gas trapped in the subsea BOP Stack.

The results of much of the research that was conducted using this well has been presented in a number of technical papers [1-9] presented in the eighties. This work, which was sponsored by

MMS, was very timely in that the record water depth for oil and gas exploratory drilling operations increased steadily during the eighties from about 1,500 ft to about 8,000 ft. Deepwater drilling operations were conducted briefly off the Atlantic coast during the eighties. The Gulf of Mexico continues to be an important area of deep water development for the United States. Brazil has also become a leader in the development of oil and gas reserves found in deep water.

Development of Improved Blowout Prevention Systems

Between 1984 and 1988, emphasis was shifted in the LSU/MMS program from the development of improved procedures for use in deep water with existing equipment to the development of improvements in the blowout prevention systems. The two major systems that were considered were the Diverter System and the Pressure Control System.

The Diverter System is employed for the shallow portion of a well, before sufficient casing has been set to permit the well to be safely shut-in. Its purpose is to divert the flow of formation fluids away from the rig and rig personnel. MMS personnel had become concerned about a high rate of diverter failure during diverter operations and had recommended that this area be addressed.

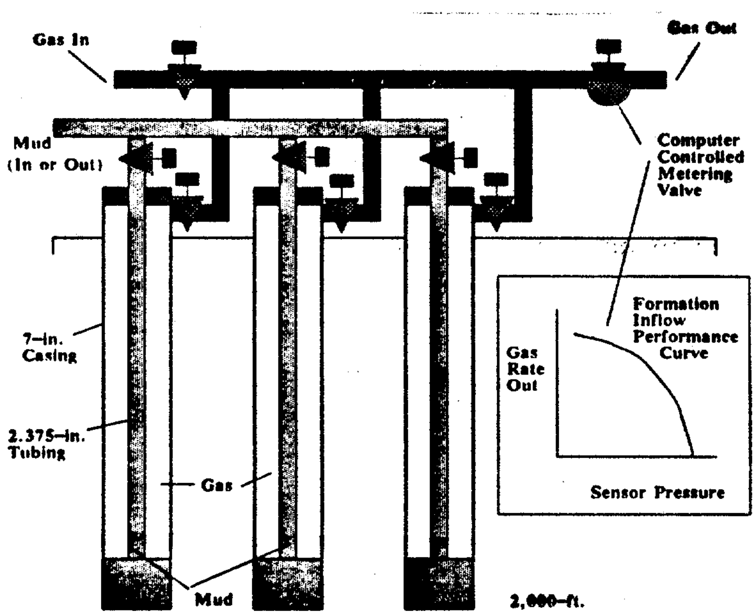

Figure 6 -Gas storage system and formation simulator.

Additional construction at the facility was undertaken to permit a model diverter system to be constructed. A 6-in. pipeline was installed which connects the facility with a natural gas transmission line that operates at 700 psi pressure. Three 2000-ft (610 m) wells were drilled and cased with 7-in., 38 lb/ft N-80 and P-110 casing. These wells were configured to allow natural gas to be compressed as high as 5000 psi for use in well control exercises (Figure 6). Pressurization is accomplished by filling the annulus of the wells with gas from the pipeline, and then compressing the gas by pumping mud down the tubing of one well, forcing the gas into the annulus of the other wells. The fill/compression cycle of one well can be repeated to obtain the final pressure desired. For some experiments, pipeline pressure is adequate and compression of the gas is not required.

Another well was drilled and cased to 1200 ft (365 m) to allow a model diverter system to be constructed (Figure 7). The diverter was constructed of 6-in., double extra strong pipe that was approximately 80-ft in length. A 7.0626-in. annular blowout preventer manufactured by Hydril is used to close the well and divert the flow through the diverter. The diverter was instrumented with four pressure transducers to provide a record of the multiphase flow pressure behavior during the unloading sequence. The exit of the diverter was above a large earthen pit that was filled with water.

A second diverter system composed of 2-in. pipe was used to study erosion problems due to formation sand being present in the well effluent. Sand was introduced to a gas flow stream from a 6000-lb sand blasting pressure pot. A 30-ton sand hopper was positioned above the pressure pot for loading it with sand. The pressure pot was also located for easy use on the larger 6-in. model diverter system.

Fundamental research on diverter systems was conducted to improve our ability to predict the pressures at various points within a diverter system at different phases of a shallow-gas-flow event and to predict the erosion rates due to the production of sand with the formation fluids. Improved design procedures that considered the conductor casing and diverter as a system were developed. A number of technical papers were presented during the mid to late eighties[10-15] that presented the results of this research. This work was also very timely in that API Recommended Practices and MMS regulations concerning diverter systems were being studied and modified during this time period.

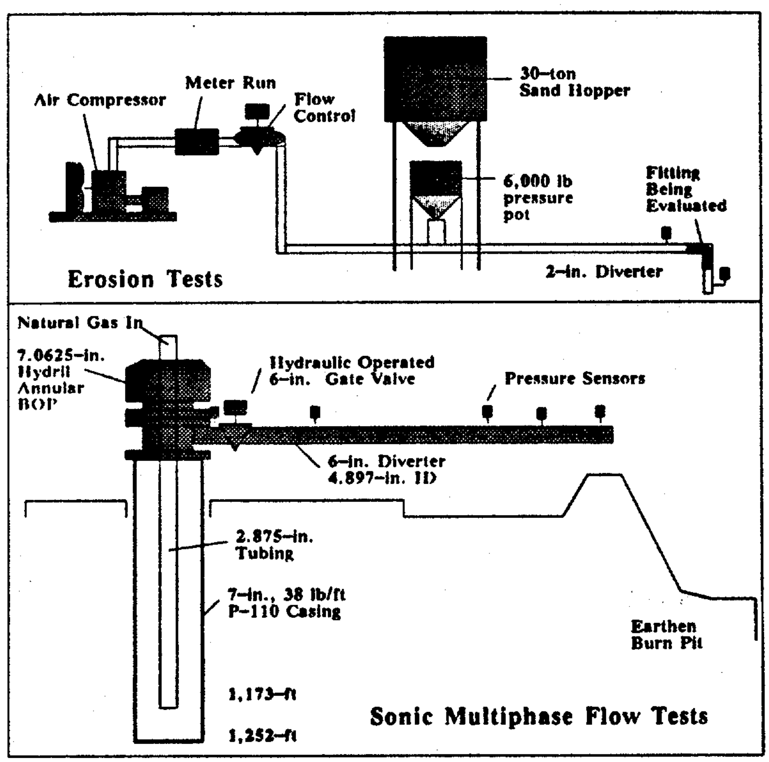

Figure 7 - Scaled diverter model.

The work on an improved Pressure Control System focused on the possibility for integrating subsurface Measurements-While-Drilling (MWD) technology with an automated well control system. Maintenance of the proper bottom-hole pressure within a small error band is more important for deep-water drilling operations because the margin between fracture pressure and pore pressure is typically much smaller. It was determined that advancements would have to be made in the data transmission rate of MWD systems to allow MWD technology to be integrated into an automated pressure control system.

A horizontal drill pipe flow loop (Figure 8) was installed at the facility to permit testing of mud pulse data telemetry systems under realistic operating conditions. Use of a horizontal system allowed access to the tool without the need to trip pipe from a borehole to gain access to the telemetry device. The 4.5-in., 20 lb/ft API drill pipe was buried at a depth of four feet with the ends located conveniently for access to the mud circulation system. The total length of the system was about 10,000-ft, and provided a excellent means for studying attenuation of the pressure pulses used to encode data and send it to the surface. A larger mud pump was provided by Halliburton for circulating this system.

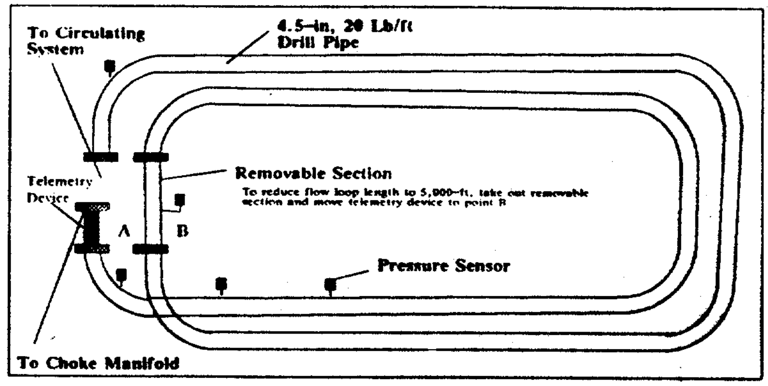

Figure 8 - MWD flow loop.

Basic research was conducted on achieving higher data transmission rates using a new fluidics mud pulser designed by Harry Diamond Laboratory. Work was also done to measure the signal attenuation rate as a function of data transmission rate for different types of mud systems. In addition, process control algorithms were developed for automatic control of the drilling choke and mud pumps during well control operations. Technical papers describing the results of this work were published during the late eighties.[16-18]

Industry Sponsored Projects

In addition to the work being sponsored by MMS, several industry sponsored projects were also undertaken during the 1984-88 period. A project sponsored by Tenneco and funded through the Drilling Engineering Association (DEA Project 4) looked at well control problems associated with gas solubility in oil-base muds. Gas solubility and oil swelling due to dissolved gas were measured in several base oils and emulsifiers used to formulate these muds. Similar measurements were also made in several mud formulations. Problems associated with kick detection and with gas cut-mud coming out of solution were also experimentally studied using the research well facility. A related project sponsored by Amoco and funded through the Drilling Engineering Association (DEA Project 7) was also conducted. In this project, down-hole measurements of methane concentration were made during well control operations in both water-base and oil-base muds. A new 6000-ft well was designed and constructed at the LSU facility that would permit down-hole logging tools to be run in the well during well control operations (Figure 9). Results obtained in DEA Project 4 were published during the late eighties.[24-26] However, because of the high costs involved, participants required that data from DEA Project 7 could not be released for several years.

Industry sponsored work on toxicity testing of oil-base muds, on rig fire suppression systems, and on freeze plug formation through injection of carbon dioxide was also undertaken in this period. Most of this work involved testing of proprietary systems developed by others. Some of the fire suppression work was sponsored by the National Fire Center of the National Bureau of Standards and Technology.

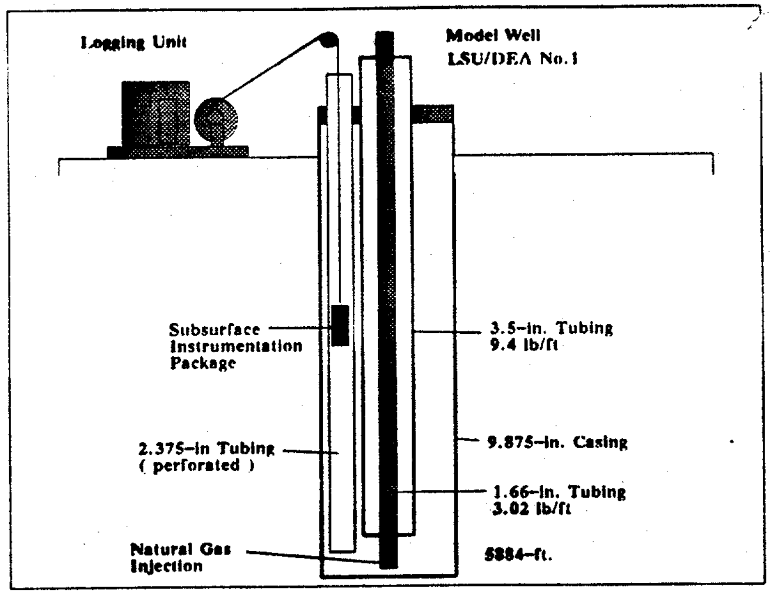

Figure 9 - Research well permitting well logging during well control operations.

Improved Contingency Procedures

In 1989, the LSU well control research effort began focusing on the development of improved contingency procedures for complications arising during offshore blowout prevention operations. An International Well Control Symposium was held in 1989 to review the results of recent and on-going well-control research and to obtain input for future research. Following this symposium, work on the development of improved diverter systems and pressure control systems continued. The integration of MWD data into an automated pressure control system was demonstrated to be feasible. In addition, correlations developed for the prediction of multiphase sonic exit pressures and for the prediction of erosion rates at bends of a diverter system were successfully extended to larger diameter pipe sizes.[19,20] The verification of our predictive models in near full-scale systems allows them to be applied to field conditions with more confidence. The effect of injected water and/or friction reducing agents as a means of reducing diverter erosion during diverter operations was studied. A computer model was developed to permit the potential application of injected water for a given field situation to be easily determined. The potential field use of a sonic-velocity detector and erosional indicator at the diverter exit was also demonstrated.

Important complications to blowout prevention operations that were identified at the International Well Control Symposium for further study included: (1) well control operations on highly deviated or horizontal wells, (2) well control problems caused by solution, diffusion, and dispersion of formation gas in oil-base muds, and (3) special problems arising after a well is placed on a diverter before it is brought under control.

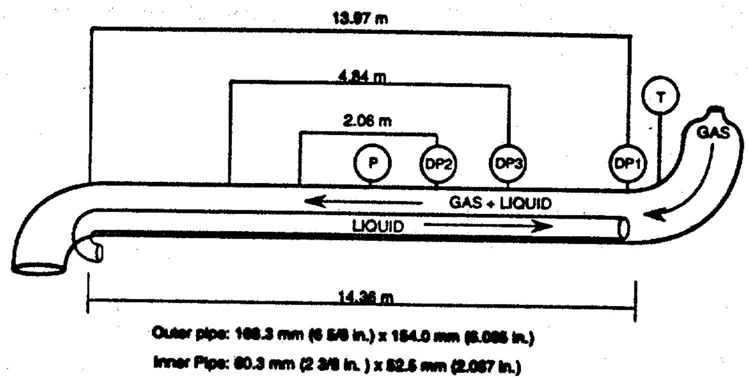

Figure 10 - Annular model for inclined multi-phase flow.

An inclined annular flow model about 49 ft (15 m) long was designed and constructed to permit basic multiphase flow studies with non-Newtonian drilling fluids. (Figure 10) The model is supported from a 100-ft derrick and permits gas concentration to be determined for various inclination angles, gas rates, and mud rates. This model allowed the development of a valuable database on gas slip velocities and gas concentration that occurs at various points in a highly deviated or horizontal well.[21] Work was also done[22,23] on developing more accurate methods of determining the surface pressures needed to obtain the desired bottom-hole pressure.

We have also studied some of the special problems that can arise after a well is placed on a diverter. One such problem is designing a dynamic kill to bring the well under control. In many past cases, a dynamic kill had to be attempted with the drill string inserted only partially into the well. The multiphase flow behavior in the bottom portion of the well for these conditions were simulated in our inclined flow loop. The experimental study provided information on how much heavy drilling fluid will fall into the bottom portion of the well, and how much will be blown out of the well for a given operating condition.

Other recently completed projects include (1) a study of the sediment failure mechanisms by which a crater can develop under an offshore structure and erode its foundations, (2) an experimental study of multiphase flow conditions during bull-heading operations, (3) an experimental evaluation of erosion resistant materials for use in diverter systems, and (4) the re-completion of one of our test wells in a new configuration that will better support our planned research and training activities. We are reporting the results of this recent work at this workshop. In addition, several technical papers have recently been prepared to help dessiminate the results of our work to industry.[27-32]

Detecting and Handling Underground Blowouts

In October, 1995, a new five year effort was initiated on well control problems associated with underground blowouts. An underground blowout differs from a surface blowout in that the uncontrolled flow exits the well beneath the surface rather than at some point above the seafloor. The formation fluids enter the well at one point and exit the well at another. The exit point could be a fractured formation, a failed cement seal, a failed casing connector, or a rupture in the casing. Underground blowouts are more numerous than surface blowouts, and sometimes contribute to a surface blowout. A recent paper by Danenberger[33] reported that the fracturing of subsurface formations allowing gas to escape to shallow sediments or to the seafloor was a contributing factor in 24.1% of the surface blowouts occurring on the outer continental shelf from 1971 to 1991.

Figure 11 - Video Camera Image of Gas and Brine Flow from Crater in Seafloor Near Subsea Well.

Salt water flows that occur outside of the conductor casing string are also a severe problem in deep water drilling in some areas of the Gulf of Mexico. In some cases, more than half of the cost of the deep water exploratory well is associated with controlling flows outside the shallow casing strings and getting a satisfactory cement job on these strings. Shown in Figure 11 is a video camera image taken from an ROV of a crater formed near a deep water well experiencing such a problem. Cratering due to such flows could be a serious hazard to the foundations of a deep water production facility.

The technology of designing a well kill for an underground blowout is not nearly as straightforward or as understood as conventional kick control. Often the well remains under pressure for a long period of time, and the subsurface well conditions are more difficult to determine from the surface pressure. This can lead to an increased risk of personnel error before the underground flow is corrected. The three main control techniques used are (1) bull-heading, (2) a dynamic kill technique for placing a region of heavy mud near bottom, and (3) placing plugging agents such as a barite pill or cement in the well. The design of the well kill is often more by trial and error than through the use of a standard calculation procedure. It has been difficult to develop good well control training modules in the area of underground blowouts because a systematic approach has not yet been defined.

In some cases involving underground blowouts, the problem may never be fully resolved, and an underground flow may continue after the well is abandoned. Such situations are often difficult to detect until a well is drilled at a later time and finds unexpected pressure at a more shallow depth. Significant loss of natural resources as well as potential environmental damage can result from undetected underground flows that continue for long periods of time.

Another problem that is sometimes related to underground flow outside of the production casing is the development of excessive pressure on an annulus between casing strings that is supposed to be sealed. Excessive casing pressure problems can occur on completed wells that are in a producing phase, in addition to problems seen while drilling. After the well is completed, diagnosing the cause of the excessive casing pressure can sometimes be very expensive. In some cases, the operator may request a temporary waiver from MMS requirements concerning the maximum allowable casing pressure seen, or they may request permission to bleed pressure off the casing. The problems and risks associated with bleeding fluids from a casing annulus that is experiencing unexpected high pressures have not been extensively studied.

The high difficulty level of the problems that are being studied will require a multi-year approach. During the current year, members of the research team are initiating work on the prevention, detection, remediation, and post analysis of underground blowouts in drilling operations. In addition, a field study of producing wells in the Gulf of Mexico with excessive casing pressure waivers granted during the past two years will be initiated. Some preliminary results obtained in this new research area will also be presented during this workshop.

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Improved Computer Model for Planning Dynamic Kill of Underground Blowouts

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Introduction

The planning of well control operations involving an induced fracture is a very complex operation and its success depends on the knowledge of reservoir and fracture characteristics, wellbore dimensions, and fluid properties.

Figure 1 shows the principal mechanisms that can take place following a well control operation involving an induced fracture. This paper focus on the case that the fracture propagates the entire time the gas reservoir produces fluid into the wellbore, as shown in the left wing of the fracture in figure 1.

constant fracture injection pressure can lead to an inappropriate estimate of the mud flow rate needed to regain control of the well.

The main objective of this study is to evaluate when the assumption of a constant fracture injection pressure will lead to unacceptable errors in the design of a dynamic kill procedure. The evaluation is accomplished using a new computer model that couples a hydraulic fracture model with a conventional reservoir and wellbore model using a system analysis approach.

Gas Reservoir Model

The gas reservoir model is based on Al-Hussainy and Ramey's (1966) expressions modified to account for changes in flow rate and pressure. To calculate the wellbore

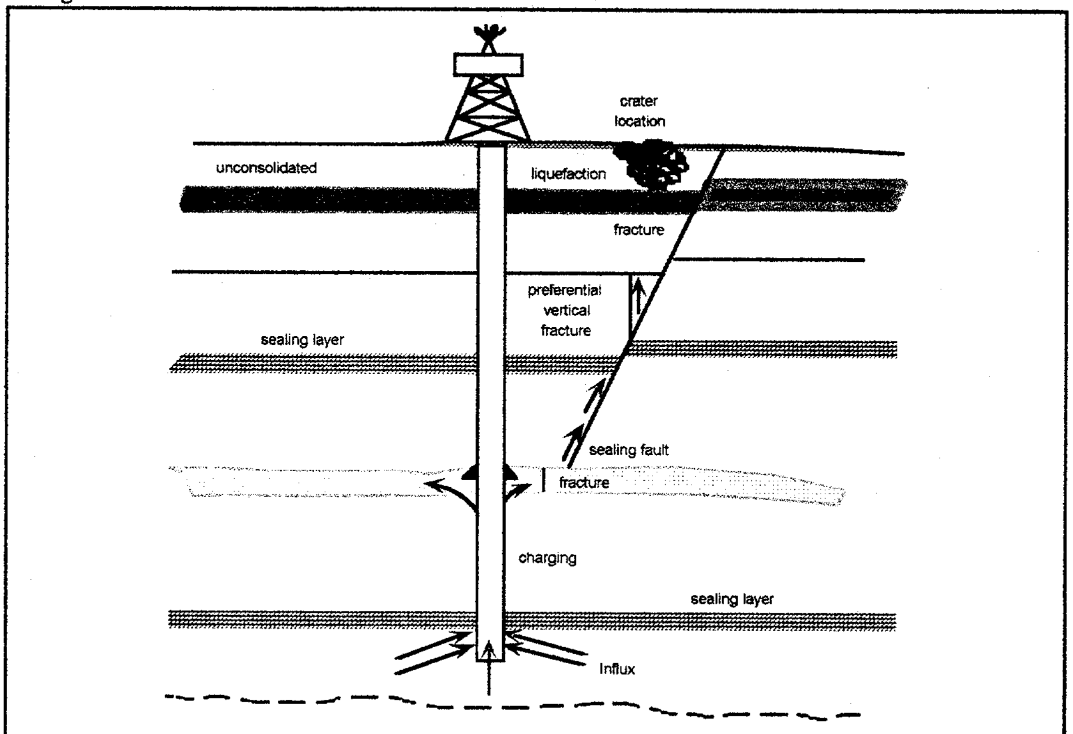

Fig. 1. Principal Mechanisms Following an Underground Blowout (after Walters, 1991)

Although many ways (the use of barite plugs, cementing, packers, etc.) to control underground blowouts exist, this paper will focus on the dynamic kill as a means to regain the control of the well. The dynamic kill method is a well control procedure that calls for pumping down the drill pipe with a flow rate that causes the bottom hole pressure to exceed the formation pressure, thus displacing the fluids out of the annulus.

Previously published procedures for planning a dynamic kill have modeled the fracture by assuming a constant pressure in the wellbore at the depth of fracture. This assumption is unrealistic because this pressure will change with time as the fracture propagates and as the flow rate is increased. This change has been shown by two-dimensional models (PKN and GdK), by fracture treatment data, and by three-dimensional models. Thus, assuming a

pressure in an infinite gas reservoir produced at a constant flow rate, including skin and the non-Darcy effects, the following expression is used:

$$\frac{\left[m(P_{RES}) - m(P_{BHP})\right] k h T_{SC}}{0.367 P_{SC} T} =$$

$$= Q\left[log(2.245 t_D) + 0.87(S + DQ)\right] \text{..............} (1)$$

where the real gas pseudo pressure is defined as:

$$m(P) = 2\int_0^P \frac{P}{z\mu_g} dP \text{.................................} (2)$$

and the dimensionless time by:

$$t_D = \frac{kt}{\phi(\mu_g c_t)_i r_w^2} \quad \text{.....(3)}$$

where the total compressibility is approximated as:

$$c_t = c_g(1 - S_{wi}) \quad \text{.....(4)}$$

The non-Darcy factor is calculated with:

$$D = 0.159 \frac{\beta_g M P_{sc} k}{R\mu h r_w T_{sc}} \quad \text{.....(5)}$$

where the velocity coefficient for consolidated sandstone was determined by Geertsma (1974) as:

$$\beta_g = \frac{0.005}{\phi^{5.5}\sqrt{k}} \quad \text{.....(6)}$$

The gas compressibility and the gas viscosity in these equations are evaluated at the reservoir pressure.

The bottom hole pressure and gas flow rate vary with time in a case of underground blowout. Due to this fact, the solution for the wellbore pressure can be found by applying the principle of the superposition for different flow rates in equation (1). The result after that is:

$$\frac{[m(P_{RES}) - m(P_{BHP})]khT_{SC}}{0.367 P_{SC} T} = \sum_{j=1}^{n}(Q_j - Q_{j-1})$$

$$log[2.245(t_D - t_{Dj-1})] + 0.87Q_n(S + DQ_n) \quad \text{.....(7)}$$

After algebraic manipulation the solution for the flow rate can be obtained from the following quadratic equation:

$$Q_n^2 + \frac{0.87S + log(2.245(t_D - t_{Dn-1}))}{0.87D} Q_n +$$

$$+ \frac{B - A - Q_{n-1}\, log(2.245(t_D - t_{Dn-1}))}{0.87D} = 0 \quad \text{.....(8)}$$

where:

$$A = \frac{[m(P_{RES}) - m(P_{BHP})]khT_{sc}}{0.367 P_{sc} T} \quad \text{.....(9)}$$

and

$$B = \sum_{j=1}^{n-1}\left[(Q_j - Q_{j-1})\, log(2.2454(t_D - t_{Dj-1}))\right] \quad \text{..(10)}$$

The flow rate for each time step in the computer model is calculated through equation (8) using the value of the bottom hole pressure in that time step.

Wellbore Model

The wellbore model is an unsteady state numerical procedure based on Santos model (1989). This model accounts for unsteady state flow effects by preserving all terms of the equation of continuity and equation of momentum for a two-phase mixture.

The program must be able to account for the two different flow conditions occurring in a well from a time just after a kick is taken until an underground blowout occurs. In the early time after a kick is taken, two distinct regions exist within the wellbore. In the lowermost section, a two-phase flow region occurs due to the mixing of kick fluid with the drilling mud in the annulus. The second region exists above the two-phase leading edge (boundary) and consists of drilling mud not yet contacted by the kick influx.

Once the kick has migrated up the annulus and induced a fracture in a shallower formation, an underground blowout is in progress. During the blowout, two-phase flow is occurring within the entire section of the borehole being modeled.

The model for two-phase flow in the annulus was based on Nickens' methodology with some modifications due to the new configuration of the problem.

The solution for unsteady state flow of two-phase mixture is based on a simultaneous solution of the continuity equations for gas and liquid phases, a momentum balance equation for two-phase mixture, an equation of state for gas and a semi-empirical relationship between the gas and liquid in-situ velocities.

The continuity equation for the liquid phase is given by:

$$\frac{\partial H}{\partial t} + \frac{\partial(v_l H)}{\partial x} = 0 \quad \text{.....(12)}$$

and for the gas phase by:

$$\frac{\partial[\rho_g(1-H)]}{\partial t} + \frac{\partial[v_g \rho_g (1-H)]}{\partial x} = 0 \quad \text{.....(13)}$$

The momentum balance equation for two phase mixture is written as:

$$\frac{\partial[(v_l F_c \rho_l H) + (v_g F_c \rho_g (1-H))]}{\partial t} + \frac{\partial}{\partial x}\Big[(v_l^2 F_c \rho_l H) +$$

$$(v_g^2 F_c \rho_g (1-H))\Big] + \left(\frac{\partial P}{\partial x}\right) + \left(\frac{\partial P}{\partial x}\right)_{elev} +$$

$$+\left(\frac{\partial P}{\partial x}\right)_{fric} = 0 \quad \text{.....(14)}$$

The elevation term for two-phase flow is calculated with:

$$\left(\frac{\partial P}{\partial x}\right)_{elev} = g(F_c \rho_l H + F_c \rho_g (1-H)) \quad \text{.....(15)}$$

The friction term is computed using the Beggs and Brill correlation which was modified to account for the non-Newtonian fluid used in drilling operations:

$$\left(\frac{\partial p}{\partial x}\right)_{fric} = \frac{f_{tf} F_c \rho_{ns} v_{mix}^2}{25.8d} \qquad (16)$$

where the two-phase mixture velocity is calculated by:

$$v_{mix} = v_l H + v_g(1-H) \qquad (17)$$

and the mixture no-slip density by:

$$\rho_{ns} = \rho_l \lambda + \rho_g(1-\lambda) \qquad (18)$$

The two-phase flow friction factor in this case can be calculated through:

$$f_{tf} = e^s f \qquad (19)$$

where f is the Fanning friction factor which is dependent on the pipe relative roughness and the two-phase Reynolds number which is given by:

$$(N_{Re})_{tf} = \frac{F_c \rho_{ns} v_{mix} d}{\mu_{ns}} \qquad (20)$$

and the non-slip viscosity is defined as:

$$\mu_{ns} = \mu_l \lambda + \mu_g(1-\lambda) \qquad (21)$$

where the liquid viscosity is the drilling fluid plastic viscosity.

The exponent (s) in equation (4.19) is defined as:

$$s = \frac{ln\, y}{-0.052 + ln\, y\left(3.182 + ln\, y\left(-0.873 + 0.0185(ln\, y)^2\right)\right)} \qquad (22)$$

where

$$y = \frac{l}{H^2} \qquad (23)$$

If y is greater than 1.2 or less than 1.0, the exponent (s) is calculated as:

$$s = ln(2.2y - 1.2) \qquad (24)$$

The fluid density of the liquid phase is considered constant and the density of the gaseous phase is related to pressure and temperature by the real gas equation:

$$\rho_g = \frac{PM}{zRT} \qquad (25)$$

In this wellbore model the gas in situ velocity is related to the liquid in situ velocity through the equation:

$$v_s = v_g - C_{fr} v_{mix} = v_g - C_{fr}\left(v_l H + v_g(1-H)\right) \qquad (26)$$

or in terms of gas velocity:

$$v_g = \frac{C_{fr} v_l H + v_s}{1 - C_{fr} + C_{fr} H} \qquad (27)$$

where the factors C_{fr} and v_s depend on flow regime. The liquid hold up defines the flow regime boundary in this study. This definition is based on Caetano Filho (1986). He verified that the bubble flow occurs when the liquid hold up is between 1.0 and 0.85, slug flow between 0.75 and 0.45 and annular flow for liquid hold up less than 0.1. For the range of values of liquid hold up not covered in the definition of the regime (H between 0.85 and 0.75, and H between 0.45 and 0.1), a transition regime is adopted with the same procedure as Santos(1989) where the in situ gas velocity is calculated through a linear interpolation between the regimes. This procedure avoids numerical inconsistencies in the solution when changing flow regimes. The equations for gas in situ velocity and the values for the factor C_{fr} were the same used by Santos(1989). They are written as:

(a) Bubble Flow:

$$v_s = 1.53 H^{0.5} \sqrt[0.25]{\frac{g_c(\rho_l - \rho_g) g \sigma_{st}}{\rho_l^2}} \qquad (28)$$

with C_{fr} equal to 1.1.

(b) Slug Flow

$$v_s = 0.289 K_1 \sqrt{\frac{(\rho_l - \rho_g) D g}{\rho_l}} \qquad (29)$$

where D is the outside diameter of the annulus,

$$K_1 = 0.345 - 0.037R - 0.235R^2 - 0.134R^3 \qquad (30)$$

and R is the ratio of the inner to outer diameters in the annulus. The value of coefficient C_{fr} is adopted equal to 1.1.

(c) Annular Flow

In this regime there is almost no slippage between phases. Therefore, the slip velocity is assumed equal to zero and the gas and liquid velocities are the same.

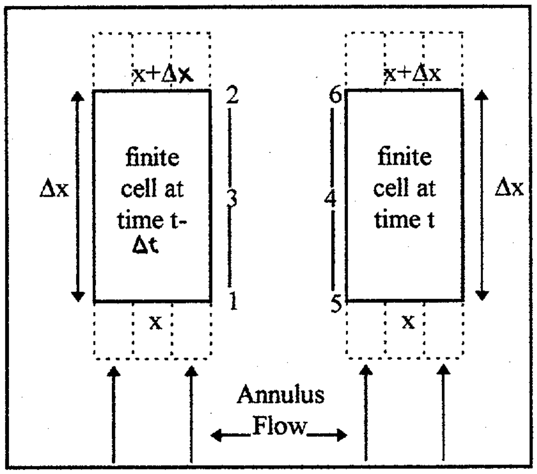

Fig.2. Finite Difference for Annulus Cell (after Santos, 1989)

The solution of the differential equation is achieved numerically by using a Finite Difference Method. This method consists of discretization of the annulus into equal finite cells where finite difference approximations of flow equations are solved. The finite difference approximation used is centered in distance and backward in time. Figure 2 shows a cell for two different time steps. The current time step is determined by the length of the cell divided by the mixture leading velocity of the previous time step.

Point 1 represents the flow properties at the previous time step and at the lower boundary and point 2 at the upper boundary. Points 5 and 6 represent the same as points 1 and 2, respectively, at the present time. Points 3 and 4 represent arithmetic averaging of the properties at the center of the grid at previous and present times, respectively. The flow properties are known at points 1, 2, and 5. The finite difference approximation estimates the flow properties at point 6.

The approximation for the space derivative in the continuity equation is calculated as:

$$\frac{\partial f}{\partial x}=\frac{f_6-f_5}{\Delta x}\ldots\ldots\ldots\ldots(31)$$

where f is some function of x and t. Substituting this approximation in the continuity equations for the liquid phase leads to:

$$\frac{(v_l\rho_l H)_6-(v_l\rho_l H)_5}{\Delta x}+\frac{(\rho_l H)_6+(\rho_l H)_5}{2\Delta t}-$$
$$-\frac{(\rho_l H)_2+(\rho_l H)_1}{2\Delta t}=0\ldots\ldots\ldots\ldots(32)$$

and for the gas phase to:

$$\frac{\left(v_g\rho_g(1-H)\right)_6-\left(v_g\rho_g(1-H)\right)_5}{\Delta x}+$$
$$+\frac{\left(\rho_g(1-H)\right)_6+\left(\rho_g(1-H)\right)_5}{2\Delta t}-$$
$$-\frac{\left(\rho_g(1-H)\right)_2+\left(\rho_g(1-H)\right)_1}{2\Delta t}=0\ldots\ldots\ldots\ldots(33)$$

The momentum balance equation is approximated by using a centered-in- distance and centered-in-time finite difference scheme. The approach for time derivative is the same, but the spatial derivative becomes:

$$\frac{\partial f}{\partial x}=\frac{f_6+f_2-f_5-f_1}{2\Delta x}\ldots\ldots\ldots\ldots(34)$$

Substituting the momentum equation into Equation 34 gives:

$$\frac{F_c}{2\Delta x}\Big[\left(v_g^2\rho_g(1-H)\right)_2+\left(v_g^2\rho_g(1-H)\right)_6-$$
$$-\left(v_g^2\rho_g(1-H)\right)_1-\left(v_g^2\rho_g(1-H)\right)_5+\left(v_l^2\rho_l H\right)_2+$$
$$+\left(v_l^2\rho_l H\right)_6-\left(v_l^2\rho_l H\right)_1-\left(v_l^2\rho_l H\right)_5\Big]+$$
$$+\frac{F_c}{2\Delta t}\Big[\left(v_g\rho_g(1-H)\right)_5+\left(v_g\rho_g(1-H)\right)_6-$$
$$-\left(v_g\rho_g(1-H)\right)_1-\left(v_g\rho_g(1-H)\right)_2+\left(v_l\rho_l H\right)_5+$$
$$+\left(v_l\rho_l H\right)_6-\left(v_l\rho_l H\right)_1-\left(v_l\rho_l H\right)_2\Big]-\frac{p_5-p_6}{\Delta x}+$$
$$+0.25\left[\left(\frac{\Delta p}{\Delta x}\right)_1+\left(\frac{\Delta p}{\Delta x}\right)_2+\left(\frac{\Delta p}{\Delta x}\right)_5+\left(\frac{\Delta p}{\Delta x}\right)_6\right]_{fric}-$$
$$-0.25\left[\left(\frac{\Delta p}{\Delta x}\right)_1+\left(\frac{\Delta p}{\Delta x}\right)_2+\left(\frac{\Delta p}{\Delta x}\right)_5+\left(\frac{\Delta p}{\Delta x}\right)_6\right]_{elev}\ldots$$
$$\ldots\ldots\ldots\ldots(35)$$

The calculation of the flow properties at point 6 requires an iterative process which uses the known flow properties at points 1, 2 and 5. The process consists of the following steps:

a) Assume an initial in-situ liquid velocity at point 6.
b) Calculate the liquid hold up through Equation (32) and determine the flow regime.
c) Calculate the in situ gas velocity.
d) Calculate the gas density at point 6 using Equation (33).
e) Calculate the pressure at point 6 using Equation (25). Use the Z value calculated for pressure at point 5.
f) With the flow properties calculated at point 6 and the assumed in situ liquid velocity, calculate the pressure at point 6 using Equation (35).
g) Compare the pressures calculated in (e) and (f). If they are within an acceptable range of tolerance, the process is over and the properties at point 6 are de-

termined. If not, assume another in situ liquid velocity and repeat the process.

If there is more than one grid, the process is repeated for the adjacent downstream grid with the properties at point 6 of the previous cell becoming the flow properties at point 5.

The induced fracture model

The fractured induction model used in the computer model is based on the assumption of an infinite plate with a circular hole in it. Poisson's ratio, Biot's constant, horizontal matrix stresses and vertical matrix stresses may be estimated from field data or correlated from a particular field.

In this work, compression is represented as positive and tension as negative. Therefore, tensile strength of the formation (S_t) is then a negative number.

The computer model only considers the expansion for vertical fracture because this occurs in almost all cases in depths greater than 500 meters. The cases of formations shallower than 500 meters will not be studied here. Therefore, the program does not analyze cases where a horizontal fracture occurs.

Vertical Fracture Initiation

Vertical fracture starts when the maximum effective tangential stress σ_θ exceeds the tensile strength of the formation S_t. Thus at fracture initiation:

$$S_t = \left(\frac{2\nu}{1-\nu}\right)\sigma_z + 2P_o - P_W + \alpha\left(\frac{1-2\nu}{1-\nu}\right)\left(P_p - P_o\right) - P_p \quad (36)$$

For a penetrating type of fluid the pore pressure (P_p) at the borehole wall is equal to the wellbore pressure, or $P_p = P_W$. Substituting this expression in the last equation and solving for P_W leads to:

$$P_f = P_W = \left(\frac{\left(\frac{2\nu}{1-\nu}\right)\sigma_z - S_t}{2-\alpha\left(\frac{1-2\nu}{1-\nu}\right)}\right) + P_o \quad (37)$$

For a non penetrating type of fluid the pore pressure (P_p) at the borehole wall is the original formation pore pressure, or $P_p = P_o$. From equation (4.36), after substituting P_p for P_o:

$$P_f = P_W = \left(\frac{2\nu}{1-\nu}\right)\sigma_z - S_t + P_o \quad (38)$$

The equations for P_W give the initiation criterion for vertical fractures. The fracture associated with the smaller P_W is the one initiated.

Fracture Expansion Model

The main objective of the model is to determine the wellbore pressure at the fractured formation in each time step. Therefore, the determination of the flow rate that is being injected into the fracture is essential to analyze the expansion of the fracture. This is done by assuming the fracture propagates in two wings, so the flow rate is equal to half of the flow rate calculated in the last cell of the wellbore model.

Although models such as Geertsma and de Klerk (1969), Nordgren (1972), Khristianovic and Zheltov (1955) and Perkins and Kern (1961) gave good results to predict the geometry of fracture in some cases, they just consider that the fracture expands in two dimensions. This can lead to miscalculations in cases where the fracture advances in three dimensions as shown in the literature review.

Also, 3-D models need parameters that are very difficult to measure. The comparison of predicted results among the existing models showed large variation in the results. In addition, the computer time to run a 3-D model is much larger than with 2-D models. This is another limitation for this kind of model because in the main program the 3-D model is coupled with a reservoir and a wellbore model.

On the other hand, a pseudo 3-D model considers the expansion of the fracture in three dimensions. This model needs few parameters which can be obtained from field data. The predicted results are realistic when compared with some 3-D models. A limitation of this model occurs when the stress contrast between the fractured formation and the bounding layers is small. In this situation the model predicts unstable and unrealistic vertical fracture migration.

The unstable vertical fracture migration can be prevented by a vertical pressure gradient in the equations that predict the fracture height. Upon consideration of these characteristics, the authors decided to use a pseudo-3D model with some modifications to analyze the fracture.

The governing equations on which the pseudo-3D models are based had to be modified to consider the compressible nature of the fluid because in an underground blowout the fluid is a mixture of a gas and a liquid phase, such as mud or water. The fracture model also assumes that the liquid hold up of the two-phase flow inside the fracture in each time step is the same as that calculated in the last cell of the wellbore model; therefore, it assumes that there is no slip or fluid segregation inside the fracture.

The pseudo-3D model used in this study assumes linear elasticity and uniform in-situ stress within each layer, so the width is calculated as follows:

$$w_T(x,y) = w_I - w_{II} - w_{III} + w_{IV} - w_V \quad (39)$$

where:

$$w_I = \frac{4\left(P(x,t)-\sigma_1\right)}{E'}\sqrt{a^2-y^2} \quad (40)$$

$$w_{II} = \frac{4(\sigma_2-\sigma_1)}{E'\pi}\left[-(b_2-y)\cosh^{-1}\left(\frac{a^2-b_2y}{a|y-b_2|}\right)+ +\cos^{-1}\left(\frac{b_2}{a}\right)\sqrt{a^2-y^2}\right] \quad (41)$$

$$w_{III} = \frac{4(\sigma_3-\sigma_1)}{E'\pi}\left[-(b_3+y)\cosh^{-1}\left(\frac{a^2+b_3y}{a|y+b_3|}\right)+ +\cos^{-1}\left(\frac{b_3}{a}\right)\sqrt{a^2-y^2}\right] \quad (42)$$

$$w_{IV} = \frac{2}{E'}g_\sigma y\sqrt{a^2-y^2} \quad (43)$$

$$w_V = \frac{2}{E'}g_P y\sqrt{a^2-y^2} \quad (44)$$

$$E' = \frac{E}{\left(1-\nu^2\right)} \quad (45)$$

The height of the fracture is determined in terms of critical stress intensity factor at the top of the crack through the equation:

$$K_{Itop} = \frac{1}{\sqrt{\pi a}}\int_{-a}^{a}\Delta P(x,y,t)\sqrt{\frac{a+y}{a-y}}dy \quad (46)$$

where:

$$\Delta P(x,y,t) = P(x,t)-g_P y-\sigma_3+g_\sigma y+g_v y \quad \text{for } -a\le y<-b_3 \quad (47)$$

$$\Delta P(x,y,t) = P(x,t)-g_P y-\sigma_1+g_\sigma y+g_v y \quad \text{for } -b_3\le y<0 \quad (48)$$

$$\Delta P(x,y,t) = P(x,t)-g_P y-\sigma_1+g_\sigma y-g_v y \quad \text{for } 0\le y<b_2 \quad (49)$$

$$\Delta P(x,y,t) = P(x,t)-g_P y-\sigma_2+g_\sigma y-g_v y \quad \text{for } b_2\le y\le a \quad (50)$$

and at the bottom by:

$$K_{Ibottom} = \frac{1}{\sqrt{\pi a}}\int_{-a}^{a}\Delta P(x,y,t)\sqrt{\frac{a+y}{a-y}}dy \quad (51)$$

where:

$$\Delta P(x,y,t) = P(x,t)-g_P y-\sigma_2+g_\sigma y+g_v y \quad \text{for } -a\le y<-b_2 \quad (52)$$

$$\Delta P(x,y,t) = P(x,t)-g_P y-\sigma_1+g_\sigma y+g_v y \quad \text{for } -b_2\le y<0 \quad (53)$$

$$\Delta P(x,y,t) = P(x,t)-g_P y-\sigma_1+g_\sigma y-g_v y \quad \text{for } 0\le y<b_3 \quad (54)$$

$$\Delta P(x,y,t) = P(x,t)-g_P y-\sigma_3+g_\sigma y-g_v y \quad \text{for } b_3\le y\le a \quad (55)$$

The vertical pressure gradient (g_v) is determined under the assumption that pressure in any cross section decreases in the direction of the tips in proportion to the pressure gradient for the lateral flow. This is the main point in a pseudo-3D model to avoid unstable vertical fracture migration. The authors assumed that this proportion depends on the ratio of height to length growth rate, or in equation form:

$$g_v = \frac{\left(a_t-a_{t-1}\right)}{dx}\frac{P(x,t)-P_L}{L} \quad (56)$$

where a_t and a_{t-1} are the half height of the cross section at current and previous time steps, respectively, and P_L is the pressure differential required to open the fracture at the crack front.

In the situation of uniform in-situ stress within each layer, the direct integration of equations (46) and (51) results in:

$$K_{Ic} = K_{I1}-K_{I2}-K_{I3}+K_{I4}-K_{I5}-K_{I6} \quad (57)$$

where:

$$K_{I1} = \left(P(x,t)-\sigma_1\right)\sqrt{\pi a} \quad (58)$$

$$K_{I2} = \frac{(\sigma_2-\sigma_1)\sqrt{a}}{\sqrt{\pi}}\left(\cos^{-1}\left(\frac{b_2}{a}\right)+f_a\frac{\sqrt{a^2-b_2^2}}{a}\right) \quad (59)$$

$$K_{I3} = \frac{(\sigma_3-\sigma_1)\sqrt{a}}{\sqrt{\pi}}\left(\cos^{-1}\left(\frac{b_3}{a}\right)-f_a\frac{\sqrt{a^2-b_3^2}}{a}\right) \quad (60)$$

$$K_{I4} = \frac{a}{2}f_a g_\sigma\sqrt{\pi a} \quad (61)$$

$$K_{I5} = \frac{a}{2}f_a g_P\sqrt{\pi a} \quad (62)$$

$$K_{I6} = \frac{2a^{1.5}g_v}{\sqrt{\pi}} \quad (63)$$

where f_c=+1 for upper or -1 for lower fracture tip of vertical section.

The final solution (57) presents two equations, one for the upper and other for the lower tip. These two equations together with an additional geometry constraint of:

$$b_3 = h_f - b_2 \qquad (64)$$

give the solution for a, b_2, and b_3.

The fluid flow in a pseudo-3D model is considered as being one-dimensional flow along the fracture length. The governing equations are basically the continuity equation for a compressible flow and the pressure gradient equation.

The continuity equation is given by:

$$-\frac{\partial(\rho_{mix}(x,t)Q(x,t))}{\partial x} = \rho_{mix}(x,t)Q_L(x,t) + $$
$$+\frac{\partial \rho_{mix}(x,t)A_{cr}(x,t)}{\partial t} \qquad (65)$$

where

$$A_{cr}(x,t) = \int_{-a}^{a} w(x,y,t)dy \qquad (66)$$

$$Q_L(x,t) = \frac{4Ca}{\sqrt{t-\tau(x)}} \qquad (67)$$

The thickness of the fractured formation is used instead of the height of fracture in equation (67) for cases where the bounding layers are impermeable.

Integration of equation (66) and the use of equation (39) allow equation (65) to be written as:

$$-\frac{\partial(\rho_{mix}(x,t)Q(x,t))}{\partial x} = \rho_{mix}(x,t)Q_L(x,t) + $$
$$+\frac{2\pi}{E'}\frac{\partial \rho_{mix}(x,t)a^2P(x,t)}{\partial t} \qquad (68)$$

The pressure gradient equation after applying the concept of apparent viscosity yields:

$$\frac{\partial P}{\partial x} + \frac{12\mu_{mix}q_x}{w^3} = 0 \qquad (69)$$

and after integrating q_x over the fracture height gives:

$$Q(x,t) = \int_{-a}^{a}\left(\frac{w^3(x,y,t)}{12\mu_{mix}}\left|\frac{\partial P(x,t)}{\partial x}\right|\right)dy \qquad (70)$$

This equation can be solved for the pressure gradient to obtain:

$$\frac{\partial P(x,t)}{\partial x} = \frac{12\mu_{mix}Q(x,t)}{\int_{-a}^{a} w^3(x,y,t)dy} \qquad (71)$$

The two-phase fluid viscosity or apparent viscosity is given as stated in Brill and Beggs (1978) by:

$$\mu_{mix} = H_l\mu_{apl} + (1-H_l)\mu_g \qquad (72)$$

where the liquid apparent viscosity is calculated through:

$$\mu_{apl} = \mu_l + 5.441\text{x}10^{-5}\frac{\tau_y A_{cr}^2}{perQ_l} \qquad (73)$$

and per is the perimeter of the fracture cross section.

The boundary conditions of equations (68) and (71) are given by:

$$Q(0,t) = \frac{q_i(t)}{2} \qquad (74)$$

$$\Delta P(L(t)/2,t) = P_L \qquad (75)$$

The value of P_L is calculated by assuming that the fracture height at its front is equal to the height of the fractured formation. So from equation (57):

$$P_L = \frac{K_{Ic}}{\sqrt{\pi a}} + \sigma_1 \qquad (76)$$

The pseudo-3D equations were solved by advancing the fracture front at a distance, ΔL, during an assumed time step, Δt, and by integrating the two flow equations by Runge-Kutta method after substituting the term involving $\frac{\partial \rho_{mix}(x,t)a^2P(x,t)}{\partial t}$ by the difference relation:

$$\frac{\partial \rho_{mix}(x,t)a^2P(x,t)}{\partial t} =$$
$$= \bar{a}^2\frac{\rho_{mix}(x,t+\Delta t)P(x,t+\Delta t) - \rho_{mix}(x,t)P(x,t)}{\Delta t} \qquad (77)$$

where $\bar{a}$ corresponds to the average half height of the fracture between the instant t and $t+\Delta t$ respectively.

The value of $Q(0,t)$ obtained is compared with $q_i(t)/2$, and if they do not agree, another value for Δt is assumed. By an iterative process the calculation is repeated until the values come within an acceptable range.

This calculation procedure, unlike other pseudo-3D models, allows the calculation of the leak-off coefficient with equation (3.8) for each cell instead of using an average leak-off coefficient for all fracture extension.

The pseudo-3D model with a vertical pressure gradient was used in fracture prediction because it gives good predictions with less computer running time. This is very important because the wellbore model is also time consuming, and the simulation of an underground blowout would require a main frame if the simulation is too long. The use of personal computers to predict pressure and flow rate in an underground blowout is better than the use of main frames due to the availability of those computers in any place.

Global Calculation Procedure

This procedure achieves the coupling among three sub models: the reservoir, the wellbore, and the fracture sub models. The procedure assumes that the pressures and liquid holdup are common to contiguous models and cells and the mass flow rate is conserved.

The first step of the procedure is the calculation of the fracture initiation pressure with equations (36) or (37) for vertical fracture. The calculation procedure will continue with the assumption that the vertical fracture initiates at the same moment as the two-phase leading edge reaches the fractured formation.

Due to this assumption, it is necessary to calculate the variables required in the fracture model at the moment the fracture starts. For that, the procedure is to calculate the properties of each cell in the annulus within each time step until the two-phase fluid reaches the fractured formation. This is done by the wellbore model that simulates a circulation of mud and gas from the moment the influx started using the pressure at the fractured formation is equal to the fracture initiation pressure. Once the two-phase fluid reaches the fractured formation, the fluid properties of the last cell in the wellbore are used in the fracture model. The propagation process then starts.

The algorithm for this calculation consists of the following steps:

a) Assume the liquid/mixture interface position and calculate the time increment by dividing the grid length by the mixture leading edge velocity for the previous time step.
b) Assume a bottom hole pressure and determine the other boundary conditions at bottom hole.
c) Determine the gas flow rate using the reservoir flow model
d) Determine the pressure drop throughout the annulus
e) Add the pressure drop to the fracture initiation pressure to determine the bottom hole pressure
f) Compare the assumed and calculated pressure values. If they are within an acceptable range, repeat the process for the next time step. If not, assume another bottom hole pressure and repeat the process.

After the two-phase leading edge reaches the fractured formation, the program starts simulating the fracture propagation and the underground blowout. This consists of the following steps:

a) With the total flow rate calculated in the last cell when the two-phase leading edge reaches the fractured formation, calculate the time step and pressure change for an assumed increment in the length of the fracture.
b) With the wellbore model using the same time step and pressure change calculated in the previous item, calculate the bottom hole pressure and the gas flow rate with the reservoir model and the pressure drop in the annulus.
c) Determine the total flow rate in the cell at the fracture formation and repeat the calculation from item (a).
d) Continue the process until the variation of pressure is negligible. The simulation for this time step is now over and the process is repeated for the next time step.

This procedure gives the variation of fracture pressure and gas flow rate produced as a function of time for the assumed mud flow rate in an underground blowout. The calculation is repeated for different mud flow rates until the appropriate rate to control the underground blowout is determined. As it can be seen in the comparison of the results, this new procedure gives different results than those calculated in the previous models. This can completely change the planning of an underground blowout.

Leak off Volume Correlation

An experimental apparatus and operational procedure were designed to study the leak-off volume occurring inside the induced fracture during an underground blowout. The result of this study is used in a fracture model to predict pressures developed during an underground blowout.

The experimental apparatus, set up at the LSU Petroleum Engineering Research and Technology Transfer Laboratory, consisted of a fluid loss cell in which a two-phase fluid passes over and through a porous core due to pressure differential. The volume that passes through the core is the leak-off volume used in the fracture model.

Description of the experimental apparatus

The test apparatus used for all fluid runs is shown schematically in Fig. 3. It can be divided in three major parts: the mixing system, the fluid loss cell, and the collector system.

The mixing system consists of two nitrogen bottles charged with a maximum pressure of 2,500 psi, a 10 gal fluid vessel, a heater, and two 20-ft rheology loops.

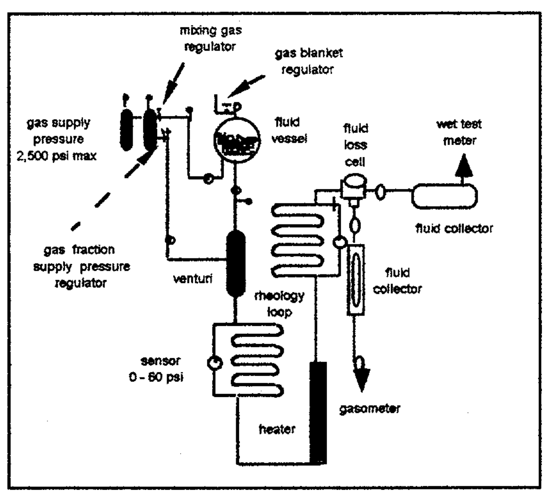

Fig. 3. Experimental Apparatus

Base drilling fluid is prepared in a small tank, pumped into the fluid vessel, and pressurized at the required level to run the experiment. The two-phase fluid mixture is obtained by small adjustments in two needle-valves situated on two lines upstream of the venturi. Once the pressure and gas flow rate are set at the start of the experiment, very little adjustment is needed to keep them at required levels. The gas and mud flow rates are measured in the collector system described later in this text.

The heater is used to maintain the fluid temperature at formation conditions, and it consists of a loop immersed in hot water.

The fluid loss cell is an apparatus in which a 0.94 x 1 inch core is set, and the fluid passes through a 1x1.5x0.13 inch slot over the core.

The collector system is used to collect the fluids that pass over and through the core, and to measure the total leak-off, the flow rate, and the gas void fraction.

Experimental Procedure

Before running the experiments, twelve Berea sandstone cores were dried in an oven for 12 hours at 250 ^{o}F, and the lateral surfaces of the cores were coated with a very thin layer of epoxy to avoid possible lateral flow during the experiment. The liquid permeability was then measured with a gas permeameter considering the Klinkenberg effect, and the porosity was measured by using mercury and an air pump.

At the end of the measurement, each core was put in a vacuum pump for three hours. Then, 50,000 ppm brine was introduced to the evacuated container to saturate the core. All the cores were allowed to saturate for a minimum of 10 days.

The fluid leak-off tests were run with five different pressure differentials of 200, 400, 600, 800, and 1,000 psi and gas void fractions varying from 0% up to 90% for each pressure differential. The pressure differential and gas void fraction were selected based on values that can be reached during an underground blowout and on values within the apparatus capacity.The mud used was a bentonite type with a viscosity of 10 cp and a density of 8.7 ppg.

The results of the total leak-off volume as function of time for all runs were plotted, and a general equation was found by using a curve fit program. The parallax error for the total leak-off volume measured in the experiment was estimated as 0.1 ml/sq cm. The equation is written as:

$$V = V_{sp}\left(1 - e^{-bt}\right) + v_D t \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (78)$$

where the parameters in this equation are spurt loss volume, the pack buildup factor, and the equilibrium Darcy flow velocity.

Those parameters depend on pressure differential, flow rate, core permeability, mud filtration property, rheological properties of the fluid, and gas void fraction.

Figure 4 shows the plot of the total leak-off volume data as function of time and gas void fraction for some runs (points in the graph), as well as the plot of equation (78) that fits the leak-off volume data (curves in the graph).

The use of equation (78) to predict the leak-off volume is possible when the spurt loss volume, the pack buildup factor, and the equilibrium Darcy flow velocity are known. The author analyzed those parameters as function of permeability, flow rate, pressure differential, viscosity, and gas void fraction.

The influence of gas void fraction on total leak-off volume is clear because the leak-off increases proportionally to gas void fraction, as can be seen in Fig. 4. The same conclusion is achieved about the pressure differential when observing the leak-off volume data. The influence of permeability, viscosity, and flow rate was not clear with the available data. The influence of the mud filtration property was not studied in this work because only one kind of mud was used in the experiment.

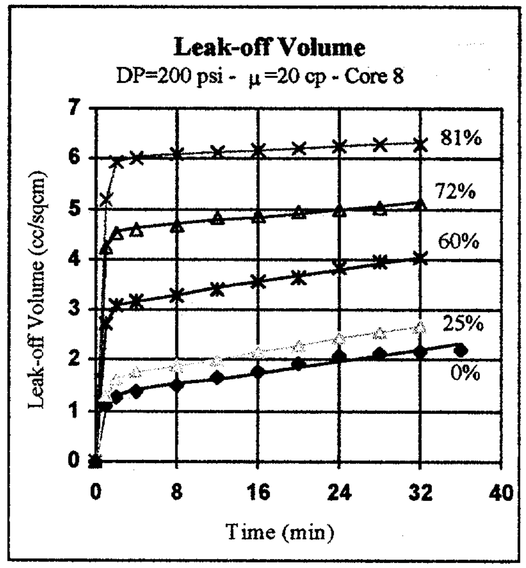

Fig. 4. Leak-off Volume for Core 8

Result

Several simulations were performed, and the results for two simulations are showed in the following figures.

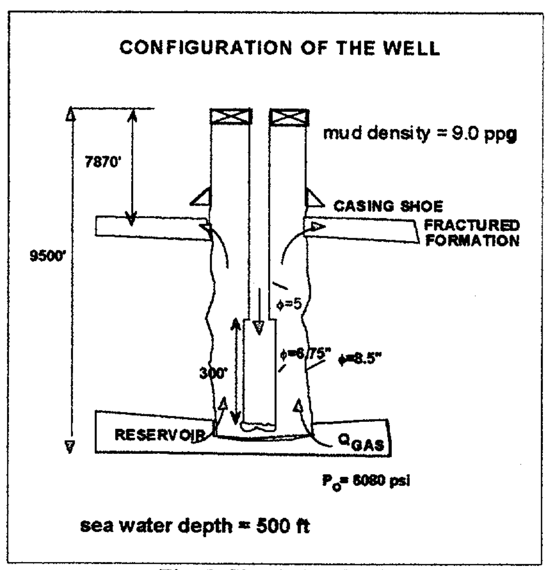

Fig. 5. Simulation for Case 1

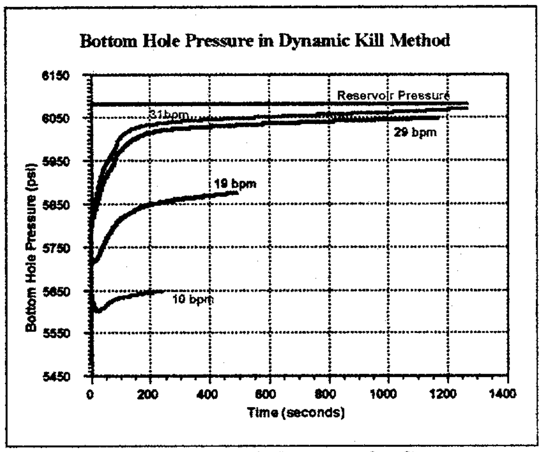

Fig. 6. Bottom Hole Pressure for Case 1

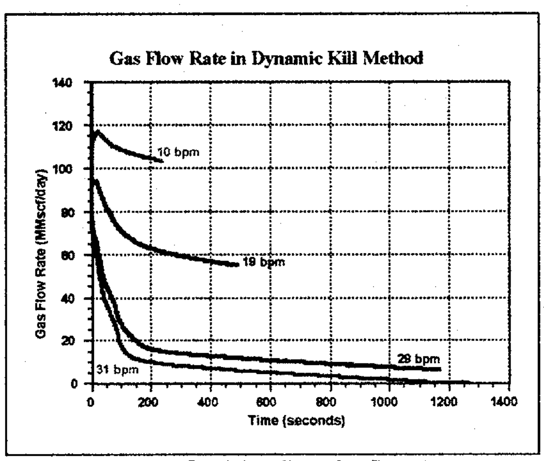

Fig. 7. Gas Flow Rate for Case 1

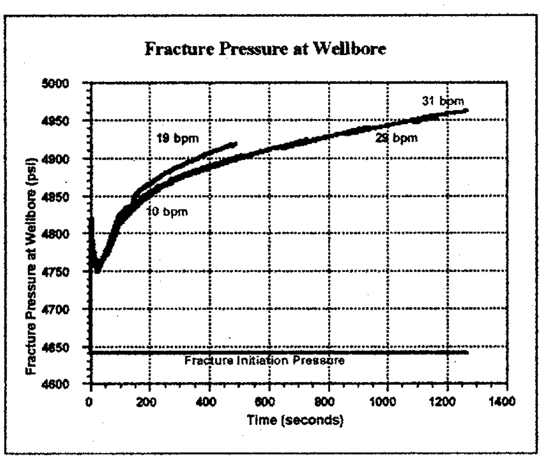

Fig. 8. Fracture Pressure at Wellbore for Case 1

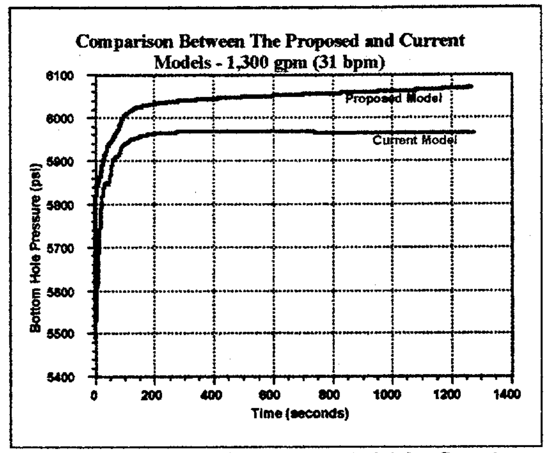

Fig. 9. Current and Proposed Model for Case 1

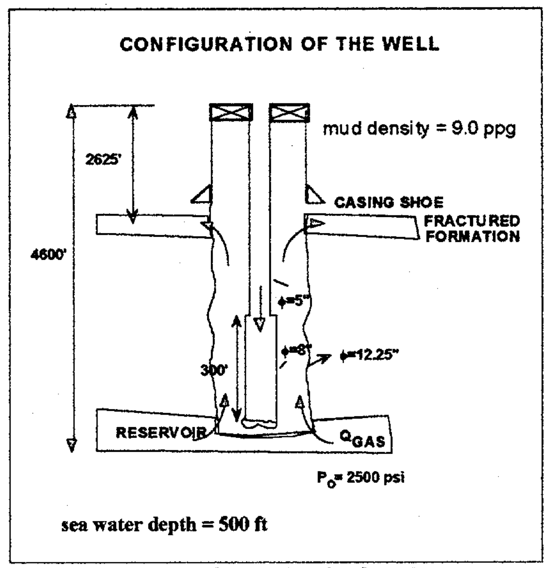

Fig. 10. Simulation for Case 2

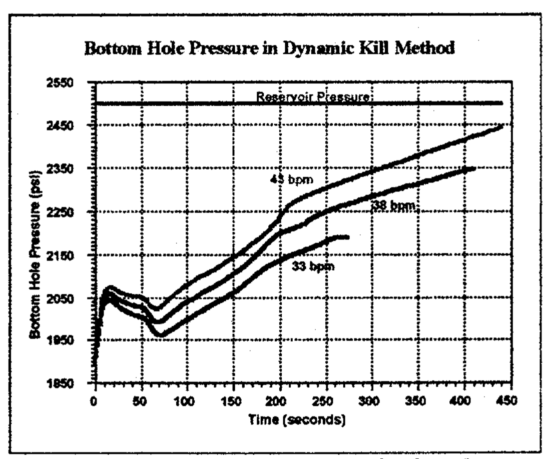

Fig. 11. Bottom Hole Pressure for Case 2

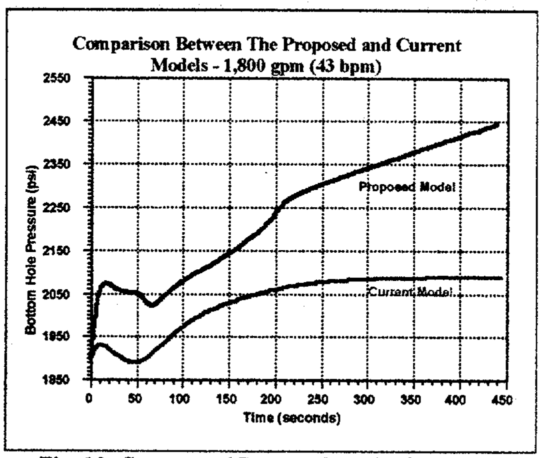

Fig. 12. Current and Proposed Model for Case 2

It can be seen from figures 5 through 12 that the proposed model can differ from the current models significantly. The difference depends on the well geometry, the reservoir and fractured formation characteristics, and the distance between the fractured formation and the reservoir. This fact is very important in planning a contingency plan to control an underground blowout because it is in this phase that the appropriate method of control is chosen.

Conclusions

It can be concluded from the simulations that:
a) The proposed model predicts different mud flow rate than the current models to control an underground blowout.
b) The difference in the mud flow rate is directly proportional to the well diameter and inversely proportional to the distance between the reservoir and the fractured formation.
c) The leak-off volume is related to time spurt loss volume, pack build-up factor, and the equilibrium Darcy flow velocity coefficient.
d) A pseudo 3D model with a pressure gradient factor predicts results that fit the results of other 3D models.

Acknowledgment

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Gas Kick Behavior During Bullheading Operations

by William L. Koederitz, *M/D Totco*

INTRODUCTION

When well control operations are necessary, circulation methods, such as the *driller's method* and the *wait-and-weight method*, are the most widely used and are generally considered the most safe and efficient. However, these circulation methods are not applicable when a kick is taken while (1) the drillstring or bit is plugged or (2) the bit is off bottom, or (3) the drillstring is out of the hole. Also, these circulation methods are not desirable when (1) the kick fluids would be hazardous at the surface, (2) a high rate or high volume of kick fluids cannot be handled at the surface , or (3) excessive pressures are expected at the surface or at the casing shoe. The bullhead method is an alternative in many of the above situations. In the bullhead technique, the operator forces mud into the well from the surface, intentionally causing a subsurface fracture as shown in Figure 1.2. When successful, all of the influx is forced out into the fracture.

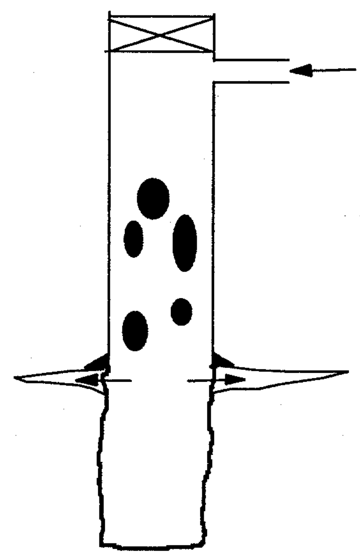
Figure 1.2 Bullhead Method

The bullhead technique is not applicable in all situations since in some instances shallow fractures may reach the surface and cause cratering or may contact fresh water aquifers. In general, these considerations limit the use of the bullhead method to wells with casing set deep enough to prevent shallow fracturing.

Bullheading is currently a trial-and-error technique since a suitable design method is not available. The primary complication in modeling bullheading is the modeling of counter-current flow. While the fluid is pumped downward, the gas has a tendency to flow upward due to the density difference between gas and fluid. Most of the published studies of two-phase flow have focused on co-current flow not counter-current flow. The only papers discussing gas rise velocity are for co-current flow. Johnston (1988) discusses counter-current two-phase flow in pipelines, but this cannot be applied directly to bullheading. No field cases directly applicable to the bullheading well control procedure were found.

A method to predict the efficiency of influx removal and the maximum pumping pressure for a given well situation, kill fluid, and pump rate is desirable. Predicting the volume of kill fluid required and the pumping time are of secondary interest, since the number and the reliability of pumping units and the supply of kill fluid are limiting factors. These secondary interests were not investigated within this study. The primary objectives of this research were (1) to investigate the influx removal efficiency for the bullhead method, (2) to identify the variables of interest, and (3) to develop simple predictive methods. A secondary objective is to develop predictive methods for maximum pump pressure.

EXPERIMENTAL APPARATUS

One of the existing gas storage wells at the LSU Petroleum Engineering Research and Technology Transfer Laboratory was selected for use in this study, since only the surface pipe required modification. A schematic of the gas storage well is shown in Figure 3.1 and the corresponding simulated well design is shown in Figure 3.2. The well is cased with 7 in., 38 lb/ft casing (inner diameter of 5.92 in., annular capacity of 0.0286 bbl/ft) to a depth of 1,994 ft. A string of 2 3/8 in., 4.7 lb/ft tubing (capacity of 0.00548 bbl/ft) extends to 1,903 ft. Pump input via a 4 in. line enters at the top of the annulus. The tubing output is routed to the SWACO automatic choke through a 4 in. return line. A downhole pressure-sensing tool is suspended on a wireline in the well. Gas is introduced into the annulus of the well via a line at the surface.

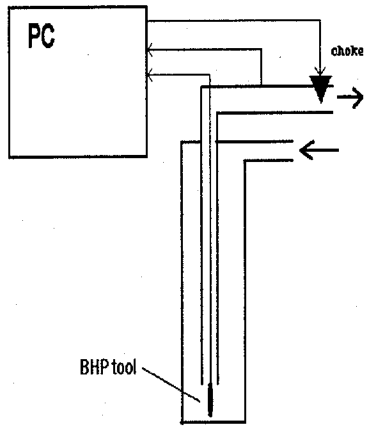

Figure 3.1 Configuration of Research Well

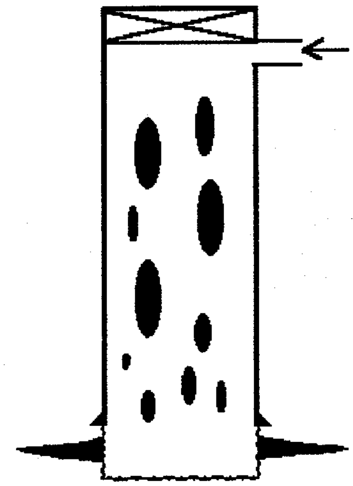

Figure 3.2 Simulated Well Design and Bullhead Situation

An analog/digital data collection and control system directed by a personal computer was installed. The input signals measured were pump pressure, choke manifold pressure, bottomhole pressure, and pump rate. All of the sensors generated 4-20 milliamp current signals, except for the bottomhole pressure sensor which produced an 11-14 KHz signal which was converted to 4-20 milliamps. Two output signals were used for control of the SWACO choke set-point pressure and the mud pump rate. Both of these were 4-20 milliamp control signals.

This combination of wellbore geometry and the computer data collection/control system allowed the tubing string to effectively simulate a subsurface fracture. The computer sensed the bottomhole pressure and the choke manifold pressure in real-time and calculated the optimum choke pressure setting for the desired fracture pressure. This resulted in the "fracture" being closed when bottomhole pressure was below fracture pressure and "opening" (allowing flow out) when bottomhole pressure reached fracture pressure. Since the gas was less dense than the fluids used, once gas and/or liquids from the wellbore entered the tubing string they were permanently removed from the annulus.

A commercially-available choke, the SWACO 10K Kick Killer, was used in this research. This choke's design is based on the "balanced piston" principle, whereby the operator (computer or human) sets a pressure level behind a floating piston which hydraulically balances against the pressure upstream of the choke assembly. This design is more adaptable to computer control, as opposed to choke designs where the operator controls the choke performance by setting an orifice position. In addition to emulating fracture pressure, the fracture logic also needed to position the choke in the optimum position for fastest response such that the choke moved closer to opening as the fracture pressure was approached. The fracture control logic was developed by separately considering the cases of the fracture being open or closed.

CONTROL SYSTEMS LOGIC

When the bottomhole pressure is below fracture pressure (i.e. the fracture is closed), the optimum choke setting is specified by:

$$P_{CKSETP} = P_{CKMAN} + \left(P_{FRAC} - P_{BH}\right) \tag{3.1}$$

This logic keeps the choke closed by the pressure differential of bottomhole pressure below fracture pressure (providing effective sealing performance), and results in the choke being on the verge of opening as fracture pressure is approached (simulating quick fracture action).

The fracture has been defined as a simple model whereby the fracture will open as needed to maintain bottomhole pressure at fracture pressure when the fracture is opened. That is, the fracture will operate (ideally) so as to prevent bottomhole pressure from exceeding fracture pressure. While this is a simple model, it is sufficiently representative for the primary purpose of studying fluid behavior in the annulus during the bullheading process. To meet the bottomhole pressure condition specified, the choke must reduce the bottomhole pressure in the event it exceeds the fracture pressure. This adjustment must also be optimized for efficient and accurate choke positioning. For the case of bottomhole pressure equal to or greater than fracture pressure, the optimum choke setting is specified by:

$$P_{CKSETP} = P_{CKMAN} - \left(P_{BH} - P_{FRAC}\right) \tag{3.2}$$

In the event that the bottomhole pressure exceeded the fracture pressure, this would reduce it by the correct amount, while maintaining flow through the fracture.

Equations 3.1 and 3.2 cover both cases for the fracture, closed and open, and cover all possible bottomhole pressures. Each of these equations is equivalent to:

$$P_{CKSETP} = P_{CKMAN} + P_{FRAC} - P_{BH} \tag{3.3}$$

This results in one direct equation for choke control and does not require knowledge of the fracture state versus time, pressure, or fracture history. An additional benefit of this relationship is that it is computationally efficient and can be used in real-time on current personal computers. Equation 3.3 was used to provide the control logic used for the formation fracture simulator in this research.

To operate the fracture in real-time, the personal computer performed the following tasks in each time step: (1) sensed the bottomhole and choke manifold pressures, (2) calculated the required choke set-point pressure, and (3) set the output current to position the choke at the desired set-point pressure. This control action was done with a direct-control system. A relationship was developed between control current and corresponding choke performance. This relationship was developed directly and dynamically by sending fixed levels of current to the choke and observing the resulting choke manifold pressure once the flow system had reached equilibrium. The pump rates were varied in these experiments, and the resulting relationship between level of control current and choke pressure was linear and independent of pump rate over a wide range of pump rates. This resulted in a direct-control relationship for choke control expressed as follows:

$$I_{CKSETP} = K_0 + K_1 P_{CKSETP} \tag{3.4}$$

Computer control of pump rate had been done before at the LSU research facility for automated well control research. However, the control of the pump rate in this research proved to be more challenging to develop. In comparison with previous research, the pump controller was subject to more severe loading demands on the pump and more rapid changes in pump discharge pressure. For the first attempt, the direct-control approach was tried and quickly proved to be unsatisfactory. Some of the complicating factors that appeared were as follows: (1) time lag between change in control current and pump response, (2) large inertia in pumping system, and (3) interaction between pump rate and pump discharge pressure.

A proportional controller with a feedback loop was developed for the pump control. In each time step, the controller performed the following tasks: (1) sense pump rate, (2) calculate the change in control current based on the needed change in pump rate, and (3) adjust the control current by the calculated change. The equation for the change in control current was as follows:

$$\Delta I_{QP} = \frac{\left(q_{P,TARGET} - q_{P,MEAS}\right)}{K} \tag{3.5}$$

In initial testing, the control factor K was held constant, as is typical for proportional controllers. While this controller performed better than the previous, its performance was not acceptable over the expected range of pump rates and under rapidly-varying discharge pressures. In particular, the controller tended to respond sluggishly when large rate changes were needed and to overshoot when small changes were needed. Further tuning to rectify these two problems was unsuccessful. The control logic was modified so that the constant factor K was replaced by the following function:

$$K = f\left(\left|q_{P,TARGET} - q_{P,MEAS}\right|\right) \tag{3.6}$$

The control program allowed the operator to modify the values and shape of the function for K. Test running the pump at different rates and pressures with linearly-varying functions for K significantly improved pump control performance. However, it was found that due to the inertia of the pump system, it was wise to limit the value of K at extreme changes in pump rate. These observations resulted in the functional shape for K shown in Figure 3.3. The control procedure implemented in the Livewell program provides recommended values for the control function, but allows the operator to change these if needed.

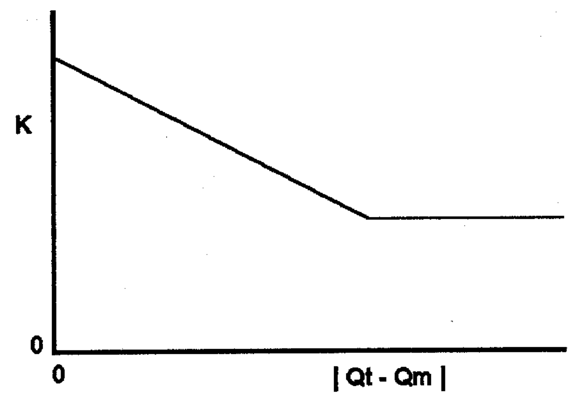

Figure 3.3 Functional Shape of Pump Rate Control "Constant"
(Qt = target pump rate, Qm = meas. pump rate)

EXPERIMENTAL DATA

Prior to injection, the gas was a continuous slug located in the upper-most section of the wellbore. The following variables were considered in this study: (1) fluid properties, (2) fluid injection rates and pressures, (3) fracture gradient, and (4) the initial gas column height and volume. The wellbore geometry and fracture depth were held constant.

A total of twelve experimental runs were completed. Water was used as the bullheading fluid for seven of the runs and a low-viscosity mud was used for the remaining five runs. Table 4.1 shows the properties of the two bullheading fluids used.

Table 4.1 Properties of Bullhead Fluids

Fluid	Density, ppg	Plastic viscosity, cp	Yield Point, lb/100sf
Water	8.34	1	0
Low-vis Mud	8.81	12	7

At the start of each experiment, gas flowed into the annulus directly from a commercial gas pipeline. This flow continued until equilibrium was reached with pipeline pressure and the height of the gas column in the well. The balance between the pipeline pressure and the fluid density resulted in gas column heights of approximately three-fourths of the well depth. Due to variations in gas pipeline pressure with time, there were small differences in initial gas column height and corresponding differences in initial gas volume. To investigate the effect of initial gas column height and volume, one experiment was repeated with an initial gas pressure of one-half of pipeline pressure. This proved to have little effect.

Table 4.3 shows a summary of the experimental runs and the removal efficiencies and all other data derived from these measurements. The experiments covered annular injection velocity ranges from 0.174 to 0.695 ft per sec and formation fracture pressures of 2,000 and 3,000 psi. The removal efficiencies ranged from 0 to 100%.

Table 4.3 Gas Volume Measurements and Injection Velocities

Bull-head Fluid	Frac-ture Press, psi	Pump Rate, gpm	Avg. Annular Velocity, fps	Initial. Gas Press, psi	Initial Gas Height, ft	Initial. Gas Volume, SCF	Final Gas Press, psi	Final BHP, psi	Final Gas Vol, SCF	Rem Eff., %
Water	2,000	12.50	0.174	650	1,572	12,094	*	*	*	0.0*
Water	2,000	25.00	0.347	589	1,404	10,001	498	680	8,123	18.8
Water	2,000	37.50	0.521	644	1,466	11,502	381	716	4,552	60.4
Water	2,000	50.00	0.695	644	1,613	12,659	109	734	422	96.7
Water	2,000	37.50	0.521	320	740	2,710	172	743	923	65.9
Water	3,000	37.50	0.521	627	1,445	10,944	483	770	6,292	42.5
Water	3,000	50.00	0.695	690	1,616	13,716	1158	1930	300	97.8
Mud	2,000	12.50	0.174	607	1,324	9,692	517	779	7,544	22.2
Mud	2,000	18.75	0.260	596	1248	8,953	380	777	4,098	54.2
Mud	2,000	25.00	0.347	616	1337	10,007	109	770	419	95.8
Mud	3,000	12.50	0.174	625	1,344	10,126	462	725	6,624	34.6
Mud	3,000	25.00	0.347	603	1315	9,568	116	867	146	98.5

* indicates computer failure

A short-hand nomenclature was used to identify the experimental runs for use on plots. Each run was identified by bullhead fluid, fracture pressure and, optionally, gas column height. For example, the first experiment was identified as "water, 2000 frac". Figure 4.1 shows the removal efficiencies for the experiments as a function of injection rate.

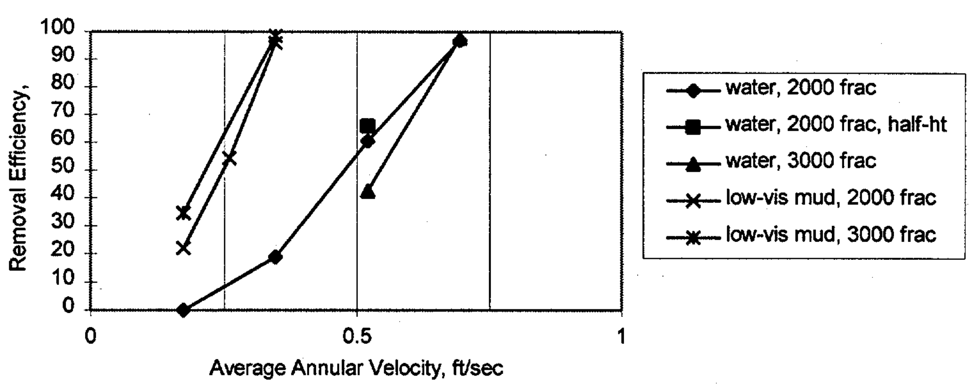

Figure 4.1 Removal Efficiencies as Function of Injection Rate

Notice that the gas is removed completely from the well for injection rates of 1 ft/sec in all cases. With the test mud in the hole, a removal efficiency of 1.0 can still be achieved with an injection rate less than half that of water.

Figure 4.2 shows the typical pressure traverse during an experimental run. The bottomhole pressure, pump pressure and choke manifold pressure gradually increase until the fracture opens. Thereafter, the bottomhole pressure remains constant, within the capability of the controller. The pump pressure plot is horizontal when there is minimal gas removal. When significant amounts of gas are removed from the annulus, the pump pressure decreases. The choke manifold pressure decreases when gas is removed from the well. Using water tends to remove the gas in a more continuous bubble-type flow, whereas the use of mud tends to create slugs of gas. High injection rates also tend to create slug flow.

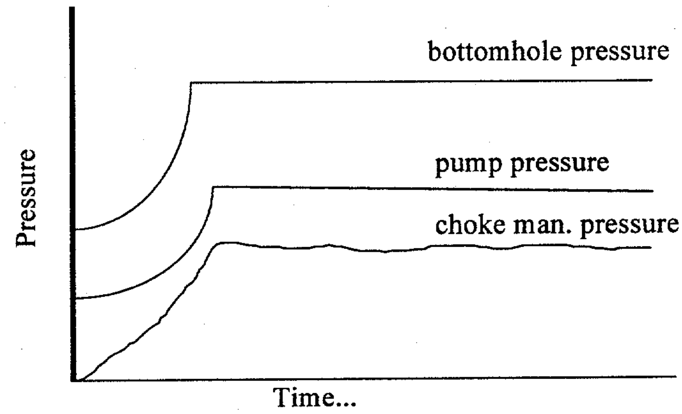

Figure 4.2 Typical Pressure Profiles During Experiments

The displacement efficiency of the bullhead fluid can also be described in terms of Reynolds Number. In this method, it is assumed that the mud completely displaces the annulus. Using a value of 2,000 to 2,200 for the transition from laminar to turbulent flow regimes, it is apparent that all of the mud experiments are in laminar flow, while all of the water experiments are in turbulent flow.

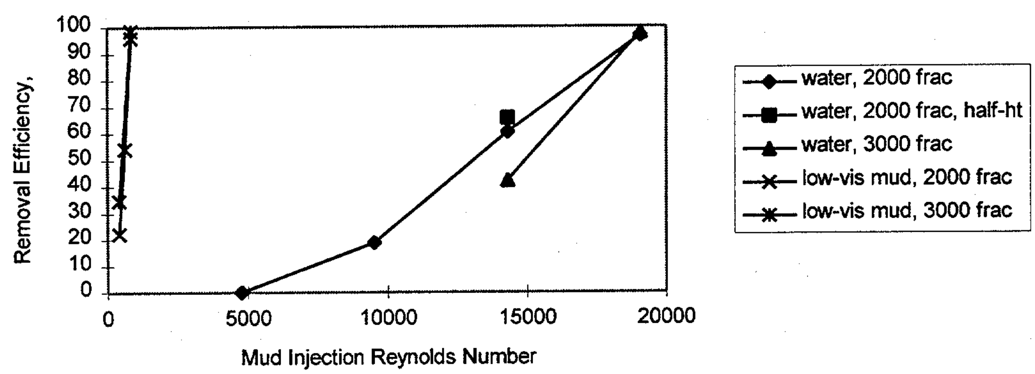

Figure 4.3 Injection Fluid Reynolds Numbers Versus Removal Efficiencies

In two-phase flow, it is common to analyze the flow behavior of the phases in terms of relative velocity, liquid holdup and similar parameters. In this experimental setup it was not possible to measure the required data at any time when the system was in a steady state. However, it is possible to describe the contents of the annulus at the time fracturing starts by considering the following. At the start of the experiment, the annulus contains a known volume of gas in a known space. The rest of the annulus and the tubing is filled with liquid. If the liquid is assumed to be incompressible and the choke is closed prior to fracture, then all injected fluid must go into the original space occupied by the gas. During this process, the gas is compressed as the pressure rises. The location of the gas in this space may vary from all gas on top (liquid bypasses gas), all gas on bottom (no liquid bypasses gas), or some condition in between. This in-between condition is a mixture of gas and liquid. A variety of methods have been used to describe the condition of this annular space at the time of fracture and to describe the traverse from the start of the experiment to first fracture. The measured factors of interest at the start of fracturing include elapsed time, pump pressure, and injected volume. From these factors, we can derive the slopes for pump pressure change during this initial injection period, in terms of pressure change per unit volume injected and pressure change per unit of time. The measured and calculated values are shown in Table 4.5.

It was observed in the experiments that the maximum pump pressure in all cases occurred at the time the fracture first opened. The pump pressure shown in Table 4.5 at start of fracturing is also the maximum pump pressure during the experiment.

Table 4.5 Experimental Conditions at Start of Fracture

	Frac P, psi	Pump Rate, gpm	Pump P at Start, psi	Pump P at First Frac, psi	Time to Frac, sec	Vol. Injected to Frac, bbl	Slope to Frac, psi/bbl	Slope to Frac, psi/min	Rem. Eff., %
Water	2,000	12.50	653	1423	7273	36.08	21.34	6.35	0.0
Water	2,000	25.00	589	1369	3052	30.28	25.76	15.33	18.8
Water	2,000	37.50	644	1468	2216	32.98	24.99	22.31	60.4
Water	2,000	50.00	644	1468	1840	36.51	22.57	26.87	96.7
Water	2,000	37.50	*	*	1380	20.54	*	*	65.9
Water	3,000	37.50	627	2465	2695	40.10	45.83	40.92	42.5
Water	3,000	50.00	690	2390	2130	42.26	40.04	47.66	97.8
Mud	2,000	12.50	607	1414	5974	29.63	27.54	8.20	22.2
Mud	2,000	18.75	596	1423	3571	26.57	31.05	13.86	54.2
Mud	2,000	25.00	*	*	2760	27.38	*	*	95.8
Mud	3,000	12.50	625	2327	6240	30.95	54.99	16.37	34.6
Mud	3,000	25.00	603	2094	3422	33.95	43.92	26.14	98.5

* indicates computer failure

RESULTS

The experimental data was analyzed and modeled by two different techniques. The goal of both approaches was to develop a method to explain and/or predict the removal efficiency and maximum anticipated pump pressure for the experimental conditions. The first technique used was a theoretical model based on two-phase flow conditions at the time of fracture initiation. The second technique was based on linear statistical modeling techniques using the primary experimental factors as predictors.

THEORETICAL TWO-PHASE FLOW ANALYSIS

The theoretical two-phase analysis can be done if liquid holdup (the fraction of liquid in the two-phase flow area) can be independently determined. Figure 5.1 shows the sequence of annular flow conditions that occur from start of injection until fracturing occurs.

At the start, all gas is in a continuous column at the top of the annulus and has an interface with the mud below. As bullheading fluid is injected into the top of the annulus, it mixes with the gas. Due to the incompressibility of the liquid below, the gas-mud interface does not move. As more liquid is injected, it continues to mix with the gas as the gas is compressed. When the bottomhole pressure has increased to fracture pressure, the fracture opens. The gas-mud interface now moves down as fluid exits the fracture.

A new interface may form on top of the gas-mud mixture such that the injected fluid is now displacing the gas-mud mixture downward. The analysis which follows is based on the assumption that the gas-mud mixture behaves as a continuous two-phase region, and investigates predicted gas velocity with observed removal efficiencies from the experimental runs.

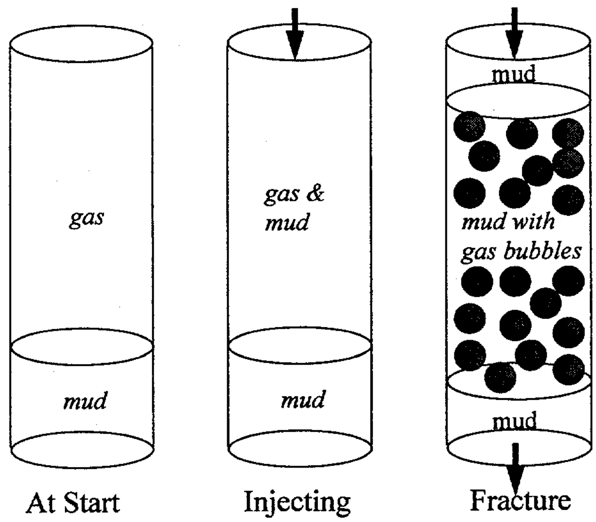

Figure 5.1 Sequence of Annular Flow States From Start to Fracture

At the time fracture occurs, the original gas volume and all of the fluid injected to that time are stored in the physical volume originally occupied by the gas alone. The average liquid holdup for the gas-liquid mixture region can be determined by:

$$H_L = \frac{V_L}{V_{ANN}} \tag{5.1}$$

The calculated values for liquid holdup for the experimental runs are shown in Table 5.1 and are plotted on Figure 5.2. The values range from 69 to 97% over the range of experimental data.

Table 5.1 Calculation of Liquid Holdup at Start of Fracture

Fluid	Frac P, psi	Pump Rate, gpm	Pump P at Start, psi	Initial Gas Volume, bbl	Vol. Injected to Frac, bbl	Average Liquid Holdup, Fraction	Rem. Eff., %
Water	2,000	12.50	650	43.59	36.08	0.828	0.0
Water	2,000	25.00	589	41.33	30.28	0.733	18.8
Water	2,000	37.50	644	41.93	32.98	0.787	60.4
Water	2,000	50.00	644	46.13	36.51	0.791	96.7
Water	2,000	37.50	320	21.16	20.54	0.970	65.9
Water	3,000	37.50	627	41.33	40.10	0.970	42.5
Water	3,000	50.00	690	46.22	42.26	0.914	97.8
Mud	2,000	12.50	607	37.87	29.63	0.783	22.2
Mud	2,000	18.75	596	36.69	26.57	0.724	54.2
Mud	2,000	25.00	616	39.55	27.38	0.692	95.8
Mud	3,000	12.50	625	38.44	30.95	0.805	34.6
Mud	3,000	25.00	603	38.67	33.95	0.878	98.5

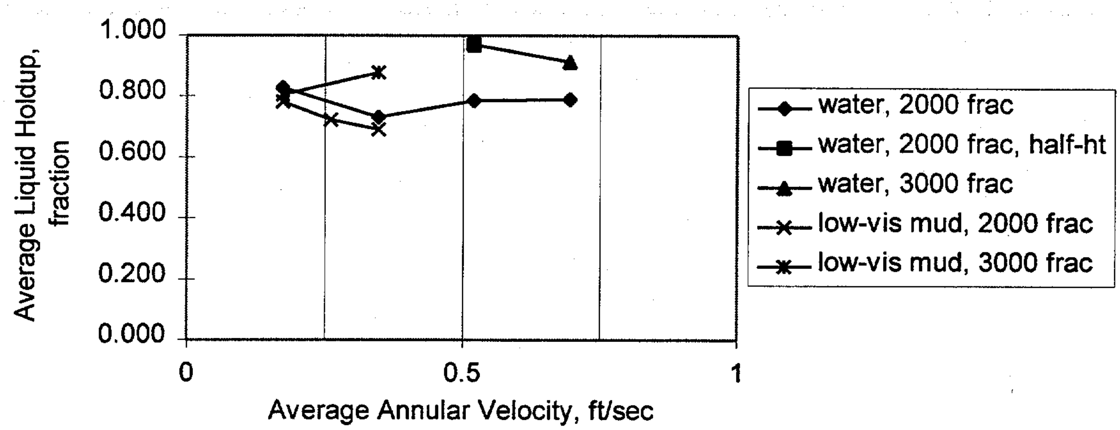

Figure 5.2 Average Liquid Holdup at Start of Fracture

Considering the gas-liquid mixture zone as one region with average properties, the velocity flux across the top interface is equal to that over the lower interface. Gas and liquid velocities are defined as positive in the downward direction. The total flux at the top is equal to the average injection fluid velocity which is also equal to the average mixture velocity. Using actual velocities and average holdup results in:

$$v_{MIX} = v_L H_L + v_G(1 - H_L) \tag{5.2}$$

The bubble rise velocity, v_0, is the velocity difference between the gas and liquid phases. Since all velocities were defined as positive in the downward direction, this is expressed as:

$$v_0 = v_L - v_G \tag{5.3}$$

Combining equations 5.2 and 5.3 and eliminating v_G results in:

$$v_L = v_{MIX} + (1 - H_L)v_0 \tag{5.4}$$

It is assumed that bubble flow is occurring in the annulus, due to the high (69 to 97%) liquid holdups (Griffith and Snyder, 1964). Since slug flow can also exist at bubble flow conditions, the test of Taitel, Barnea and Dukler (1980) (Eqn. 2.13) was used to confirm that slug flow did not exist. The test was done using the conditions most conducive to slug flow (minimum gas density) that occurred in the experimental data. The inequality test result was "5.96>0.79"; confirming the occurrence of bubble flow by the truth of this comparison and the relative values. The velocity difference between the gas and liquid phases for bubble flow can be estimated by the Harmathy equation:

$$v_0 = 1.53\left(981\frac{\rho_L - \rho_G}{\rho^2}(70)(8.33)\right)^{0.25}(0.03281) \tag{5.5}$$

Since the average liquid holdups have been estimated, the following procedure can be used to obtain the velocities of both phases for each experiment:

1. For gas, calculate average pressure, z-factor and density.
2. Calculate bubble rise velocity using equation 5.5.
3. Calculate liquid velocity using equation 5.4.
4. Calculate gas velocity using equation 5.3.

The calculations are shown in Table 5.2. Since the pump pressure at fracture is needed to estimate gas density, it is not possible to use the data from the two experimental runs that experienced computer failure and loss of data. These runs are denoted by "*" in Table 5.2.

Table 5.2 Calculation of Liquid and Gas Velocities at Start of Fracture

Fluid	Frac P, psi	Pump Rate, gpm	Avg. Gas P at Frac, psi	Avg. z Factor at First Frac	Gas Density at First Frac, ppg	Average Liquid Holdup, Fraction	Liquid Vel., ft/sec	Gas Vel., ft/sec
Water	2,000	12.50	1712	0.82	0.80	0.828	0.310	-0.482
Water	2,000	25.00	1685	0.82	0.79	0.733	0.559	-0.234
Water	2,000	37.50	1734	0.82	0.81	0.787	0.690	-0.102
Water	2,000	50.00	1734	0.82	0.81	0.791	0.860	0.068
Water	2,000	37.50	*	*	*	0.970	*	*
Water	3,000	37.50	2733	0.81	1.29	0.970	0.544	-0.235
Water	3,000	50.00	2695	0.81	1.27	0.914	0.762	-0.018
Mud	2,000	12.50	1707	0.82	0.80	0.783	0.344	-0.438
Mud	2,000	18.75	1712	0.82	0.80	0.724	0.476	-0.307
Mud	2,000	25.00	*	*	*	0.692	*	*
Mud	3,000	12.50	2664	0.81	1.26	0.805	0.324	-0.447
Mud	3,000	25.00	2547	0.81	1.20	0.878	0.441	-0.331

Figures 5.3 shows the calculated gas velocity as a function of average annular velocity. Inspection of Figure 5.3 shows the gas velocities to be fairly linear with average annular velocity. This is especially true at the lower annular velocities. This applies to gas flow in both directions, downward and upward (a positive velocity was defined to be downward flow). This appears to indicate that the annular flow behavior is similar across the range of the experimental conditions. This is further confirmed by the similarity in liquid holdups. All of these observations are limited to the annular condition at the time fracture first occurs. However, it is postulated in this research that the conditions at the time fracture first occurs significantly affect the displacement processes in the annulus once fracturing starts.

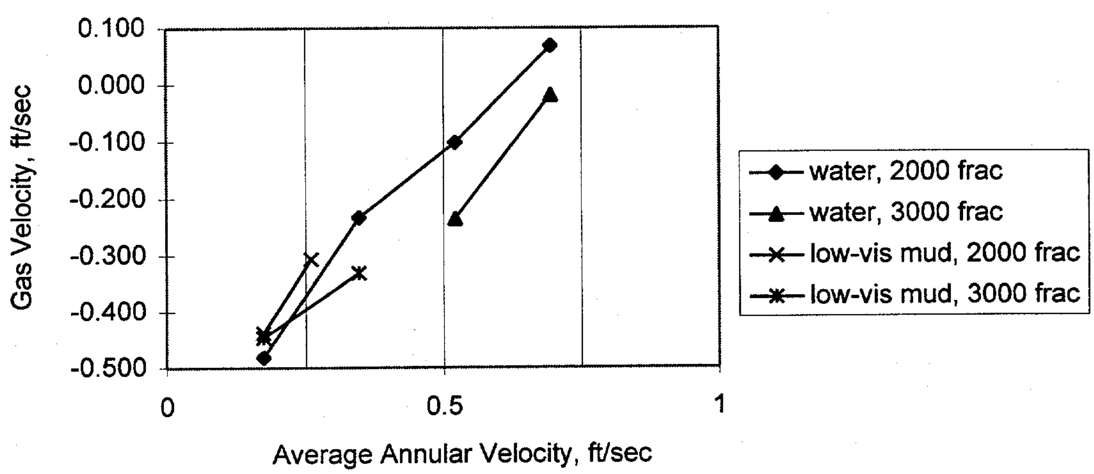

Figure 5.3 Gas Velocities for Experiments

Figure 5.4 shows the removal efficiencies for the experimental runs plotted versus the calculated gas velocities. For all experimental runs, gas velocity is positively correlated with removal efficiency. That is, higher removal efficiencies occurred at higher gas velocities for a given fluid type and fracture pressure. For water, the results are particularly interesting; the complete (or near complete) removal of gas occurred as gas velocities approached positive values. This indicates that the gas as a whole is flowing downward with the bullheading fluid. This is not true for the low-viscosity mud, where high removal efficiencies occurred at lower gas velocities. The low-viscosity mud with 3,000 psi fracture pressure deviates the most from the ideal behavior (high removal efficiency at a calculated upward gas velocity). The "low-vis-mud, 2000 psi frac" case falls in-between the water cases and the "low-vis mud, 3000 psi frac" cases. The primary reason suggested for these differences is that the Harmathy correlation for gas bubble rise velocity is more applicable to water than the viscous drilling mud. Also, the Harmathy correlation is likely more applicable for gas at lower pressures for the low-viscosity mud cases.

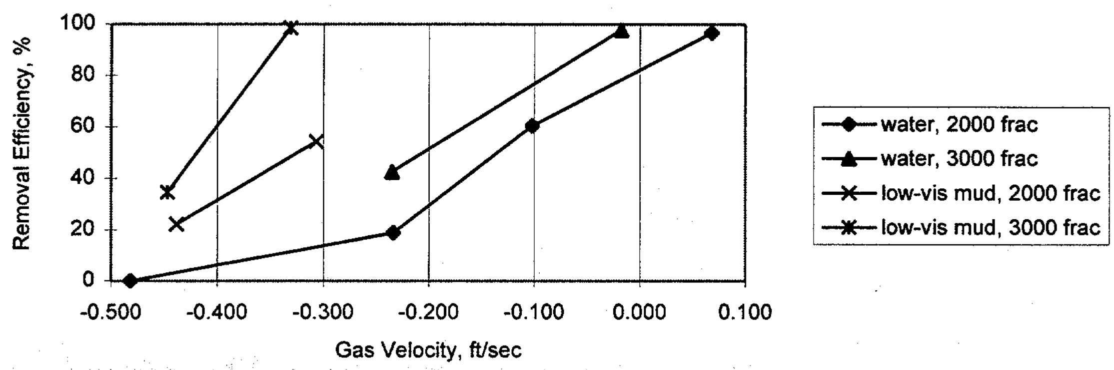

Figure 5.4 Relationship Between Gas Velocity and Removal Efficiency

All of the curves on Figure 5.4 appear to extrapolate to a common negative (i.e. high upward) velocity at near-zero removal efficiencies.

STATISTICAL ANALYSIS OF EXPERIMENTAL DATA

Multiple regression analysis was used in an attempt to develop a predictive method for removal efficiency and maximum pump pressure during bullheading operations. A computer program was used to perform the statistical calculations.

The general estimating model for multiple linear regression is:

$$Y = b_0 + b_1 X_1 + b_2 X_2 + ... + b_n X_n \tag{5.6}$$

where:

Y	=	estimated value of dependent variable,
b_0	=	estimated value for intercept,
b_i	=	estimate for coefficient for X_i,
X_i	=	value of dependent variable i.

Based on the observations made in the Experimental Data section and in the Theoretical Two-Phase Flow Analysis portion of the Results section, nine variables were selected for statistical review. These variables are shown in Table 5.3 along with the short-hand names used for convenience in the analysis and simple descriptive statistics.

The dependent variables of interest are removal efficiency and maximum pump pressure. The primary parameters characterizing each experimental run are fluid used, fracture pressure, and injection rate. Two fluids were used, water and a low-viscosity mud; their properties are described in the Experimental Data section. These fluids were described by an indicator variable, with values of zero for water and one for the mud. The indicator variable was used instead of the actual fluid properties because there were only two fluids used. Use of the fluid properties would add three variables (density, plastic viscosity, yield point) to the model, all correlated to fluid type.

Table 5.3 Experimental Variables Used in Statistical Analysis

Variable	Name	Count	Mean	Standard Deviation
Removal Efficiency, %	RE	12	52.6	35.6
Max. Pump Pressure, psi	PPFRAC	10	1784	470
Injection Fluid	FL	12	N/A	N/A
Fracture Pressure, psi	FRAC	12	2400	516
Injection Velocity, fps	IVEL	12	0.391	0.206
Gas Column Height, ft	HTGAS	12	1441	117
Reynolds Number	NREY	12	8333	7863
Liquid Holdup, fraction	H	12	0.821	0.078
Gas Velocity, fps	VGAS	10	-0.252	0.187

The correlation matrix for the experimental variables chosen is shown in Table 5.4. The removal efficiency is correlated positively with injection velocity. This is apparent from the experimental data. There is no useful information regarding the fluid type (an indicator variable) and fracture pressure since high recoveries were obtained for both fluids. However, the pump pressure at start of fracture is strongly related to fracture pressure only. This strong relationship was the most useful information obtained from the correlation analysis. The other dependent variables are generally unrelated. The few strong relationships that are found are due to interdependencies, particularly with calculated values. This applies to injection velocity, Reynolds Number, holdup and gas velocity. Of these variables, only injection velocity will be used in the following analysis.

Table 5.4 Correlation Matrix for Experimental Variables

	RE	PPFRAC	FL	FRAC	IVEL	HTGAS	NREY	H	VGAS
RE	1.0000	0.3465	-0.0047	0.3813	0.7282	0.3223	0.4438	0.3057	0.7103
PPFRAC		1.0000	0.0556	0.9787	0.2621	0.0704	0.1553	0.8169	0.0485
FL			1.0000	0.1667	-0.6361	-0.8474	-0.8490	-0.2615	-0.5899
FRAC				1.0000	0.1818	-0.0143	0.0353	0.7762	-0.0241
IVEL					1.0000	0.7467	0.9321	0.4044	0.9600
HTGAS						1.0000	0.8659	0.3318	0.6951
NREY							1.0000	0.3586	0.8923
H								1.0000	-0.2615
VGAS									1.0000

The first regression relationship tried was removal efficiency as a function of fluid type, fracture pressure, and injection velocity. An R^2 value of 0.8728 was obtained, with the following equation:

$$RE = -108.1 + 59.13 * FL - 0.00285 * FRAC + 221.8 * IVEL \qquad (5.7)$$

This shows an increase in removal efficiency with mud (over water) and with increased injection velocity, and shows a slight decrease at higher fracture pressure.

The next relationship tested was to predict maximum pump pressure. In the first attempt, all three key variables (fluid type, fracture pressure and injection velocity) were included. This produced the following equation:

$$PPFRAC = -278.0 - 87.79 * FL + 0.9027 * FRAC + 47.35 * IVEL \quad (5.8)$$

This equation had an R^2 value of 0.9699. While this was a strong predictor for the data, 99.7% of the model's sum-of-squares was contributed by the FRAC term. In addition, the experimental data and the high correlation coefficient indicate a strong relationship between maximum pump pressure and fracture pressure.

Accordingly, the prediction of maximum pump pressure from fracture pressure only was investigated next. The following relationship resulted:

$$PPFRAC = -355.5 + 0.8915 * FRAC \quad (5.9)$$

This resulted in a very slight drop in R^2 (from 0.9699 to 0.9578) and a more robust model. Applying this equation to the experimental data yielded the following predictions:

Table 5.5 Maximum Pump Pressure Predictions from Equation 5.9

Fluid	Frac P, psi	Pump Rate, gpm	Measured Maximum Pump Pressure, psi	Estimate of Maximum Pump Pressure, psi	Residual, psi
Water	2,000	12.50	1423	1427	-4
Water	2,000	25.00	1369	1427	-58
Water	2,000	37.50	1468	1427	41
Water	2,000	50.00	1468	1427	41
Water	2,000	37.50	*	1427	*
Water	3,000	37.50	2465	2319	146
Water	3,000	50.00	2390	2319	71
Mud	2,000	12.50	1414	1427	13
Mud	2,000	18.75	1423	1427	-4
Mud	2,000	25.00	*	1427	*
Mud	3,000	12.50	2327	2319	8
Mud	3,000	25.00	2094	2319	-225

* indicates computer failure

Of the ten estimated values, all but two are within 75 psi of the measured value. The most extreme error, -225 psi, occurs for the "mud, 3000 psi frac, 25 gpm injection rate". This appears to be an anomaly; however, due to the small quantity of data, it will be included in the analysis until further data is collected.

Given the ability to predict pump pressure at the start of fracturing and indications that the annular condition at that time may affect the removal efficiency, a new model for predicting removal efficiency was tried. The following changes were made, compared to the previous regression model for removal efficiency:

1. The estimated maximum pump pressures, using Equation 5.9, were added to the list of independent variables.

2. The "water, 2000psi frac, 12.5gpm" case was removed from the dataset. This was based on the observation that the "true" injection rate for zero removal is above this rate, making this an artificial point that distorts an apparently linear relationship.
3. An auto-correlating regression analysis was used, investigating all combinations of the four dependent variables (fluid type, fracture pressure, injection rate, estimated maximum pump pressure) to find the best model.

This "best fit" model found contained only two of the dependent variables (fluid type, injection rate). The following is the resulting model:

$$RE = -161.4 + 75.9 * FL + 271.3 * IVEL \qquad (5.10)$$

This equation had an R^2 of 0.8872 and produced the predictions shown in Table 5.6.

Table 5.6 Removal Efficiency Predictions from Equation 5.10

Fluid	Frac P, psi	Pump Rate, gpm	Measured Removal Efficiency, %	Estimate of Removal Efficiency, %	Residual, %
Water	2,000	12.50	N/A	N/A	N/A
Water	2,000	25.00	18.8	8.6	10.2
Water	2,000	37.50	60.4	55.8	4.6
Water	2,000	50.00	96.7	103.0	-6.3
Water	2,000	37.50	65.9	55.8	10.1
Water	3,000	37.50	42.5	55.8	-13.3
Water	3,000	50.00	97.8	103.0	-5.2
Mud	2,000	12.50	22.2	37.6	-15.4
Mud	2,000	18.75	54.2	61.0	6.8
Mud	2,000	25.00	95.8	84.6	11.2
Mud	3,000	12.50	34.6	37.6	-3.0
Mud	3,000	25.00	98.5	84.6	13.9

As a check on the auto-correlation procedure, independent variables were manually added to and removed from the model; these did not result in improved models. For example, adding fracture pressure to the model increased R^2 from 0.8872 to 0.8897. This model also showed a 7% chance that the coefficient for fracture pressure was zero. Although the model in Equation 5.10 appears to be simple and omits an important variable, Equation 5.10 is the best predictive model based on the experimental data.

Equations 5.9 and 5.10 provide the best estimating technique for this set of experimental data. It is expected that they will provide a basis for improved estimating methods upon further collection of data. Upon collection of more data, it is felt that the use of predictive techniques for the wellbore conditions at the start of fracture, such as maximum pump pressure, liquid holdup and gas velocity, will result in improved models for removal efficiency.

While the two-phase flow approach did not result in promising predictive models for this set of data, the analysis did lend credence to the annular behavior at the start of fracturing. It also showed some correlation between estimated gas velocities and removal efficiencies. While all of these correlations were positive, the cases with water as the bullhead fluid were the most convincing. Upon collection of more data, the two-phase flow approach should be re-tested.

CONCLUSIONS

1. Based on the experimental data, the removal efficiencies for bullheading appear to increase linearly with increasing injection rate, irrespective of the other variables tested. Complete removal of the gas is guaranteed for all cases if the injection rate is greater than 1 ft/sec.

2. The predictive model for maximum pump pressure used formation fracture pressure as the dependent variable. Fluid type and injection velocity were not significant factors in this model. The predictive model for removal efficiency used fluid type (water or mud) and injection velocity as dependent variables. Fracture pressure was not a significant factor in the model. The statistical and theoretical analysis of both models indicates that their use should be limited to the range of the data collected in this experiment. The models would be significantly improved by additional experimental data.

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Experimental Study of Erosion Resistant Materials For Use in Diverter Components

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Abstract

A diverter is a safety device used on oil and gas drilling rigs as a means of handling shallow gas flow. A common mode of failure of the diverter is erosion of the bends in the surface vent lines that divert the flow away from the rig.

The objectives of the study carried out at LSU were to identify new or alternate materials that are more resistant to sand erosion than those that are currently being used in the field, thereby enhancing diverter system operational safety; and to obtain sufficient experimental data to allow estimation of life of a component that is used to make a bend in a diverter system.

Work done includes experiments on low carbon steel flat plates and various other erosion resistant materials by maintaining sonic velocity of the carrier fluid. Study of the effects of various parameters such as angle of impact and rate of sand flow on the erosion rates of these materials was also carried out.

Low carbon steel of A-36 specifications had the maximum erosion rate when blasted with sand grain size of US mesh # 80-120 at an impact angle of thirty degrees. Stellite 6K showed the least erosion rate among the materials tested under similar conditions. When the angle of impact was changed to ninety degrees, keeping all the other parameters the same as before, low carbon A-36 steel showed the maximum erosion rate once again and the performance of stellite 6K remained near the best of the materials tested. Comparing the erosion performance of these materials at different angles indicates that erosion is a greater problem at thirty degrees than at ninety degrees. It was found that the life of a diverter component could be increased by almost 100% if it is coated with stellite 6K over the use of uncoated low carbon A-36 steel.

Introduction

Blowouts are among the most dangerous hazards of oil and gas exploration. When a well threatens to blowout, the prompt use of properly designed blowout prevention equipment is necessary to avoid harm to personnel and loss of the drilling structure. Well control is especially difficult when a threatened blowout situation occurs at a shallow depth. During the course of drilling operations, periods often exists when the well should not be closed on a threatening blowout as the formation are not competent enough to keep an underground blowout from broaching to the surface. When a threatened well blowout situation occurs and none of the other conventional methods of controlling the well can be used, a diverter system must be used.

A diverter system is a safety device used on oil and gas drilling rigs to direct uncontrolled flow of formation fluids away from the rig. This system is composed of some means for changing the direction of flow from vertical to horizontal, usually with an annular packing element, and a pipe system that leads the flow away from the rig. The essential elements of a diverter system include a vent line for directing flow away from the rig, a means for closing the well annulus above the vent line during diverting operations, and a means for closing the vent line during normal drilling operations.

The diverter must function for at least enough time to allow for an orderly evacuation of rig personnel. The past performance of diverter systems has been very poor. Failures have been caused by excessive pressure losses through the diverter system, operational problems with valves, and erosion of valves and vent lines. The use of larger vent sizes and selection of an appropriate conductor casing depth can reduce the risk of high back pressure. Proper selection of diverter valves and valve operations, followed by periodic maintenance and testing, can eliminate operational problems with valves.

It has been observed that a common cause of diverter failure is erosion. Erosion can be caused by cavitation and by impingement of liquid or solid particles. Erosion by impingement of solid particles is most rapid and therefore it is of primary concern for diverter operations. A specific erosion factor, F_e, is often used to express the erosion caused by particle impact. This factor is defined as the mass of steel removed per unit mass of abrasive. Erosion occurs predominantly at points where the flow changes direction, such as a bend in the diverter. A straight diverter vent line is always the preferred choice but turns in the vent lines are sometimes unavoidable when a diverter is installed on an existing rig due to the equipment layout.

Previous Work

In the past, several investigators studied the effects of varying impact angle, particle velocity, particle mass, and properties of the abrasive particle and target materials on erosion rate.

The majority of experimental work to investigate the effects of impacting velocity on erosion rate has proven erosion rate to be proportional to velocity raised to the second or third power. The study by Finnie (1967) found the velocity exponent to be between 2.48 and 2.69 when the target was annealed SAE 1215 steel. The effect of velocity on erosion rate is shown below.

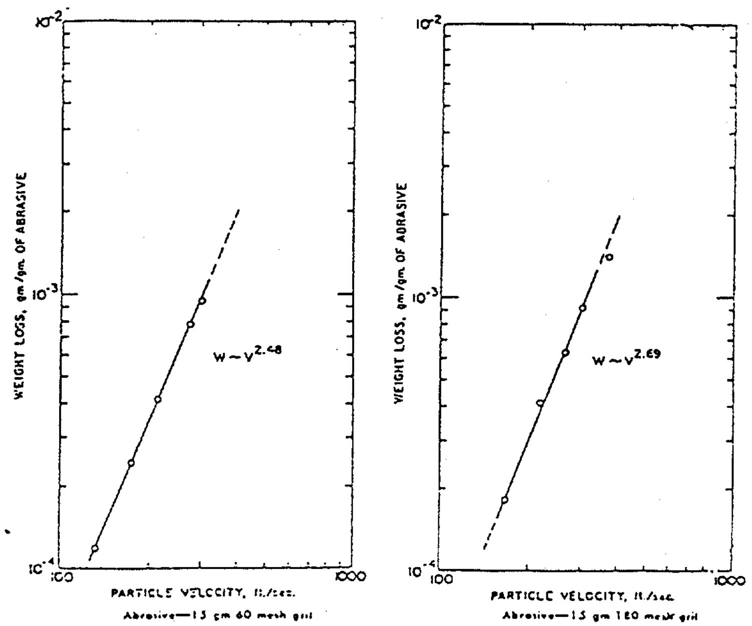

Figure 1: Effect of velocity on specific erosion of annealed SAE 1215 steel, 20 degrees impact SiC (from Finnie 1967)

Ives and Ruff (1978) found that erosion rate for a ductile material was maximum at an impact angle of about 20 degrees while brittle materials underwent maximum erosion at normal angles of attack. Figure 2 shows the effect of angle of impact on erosion rates.

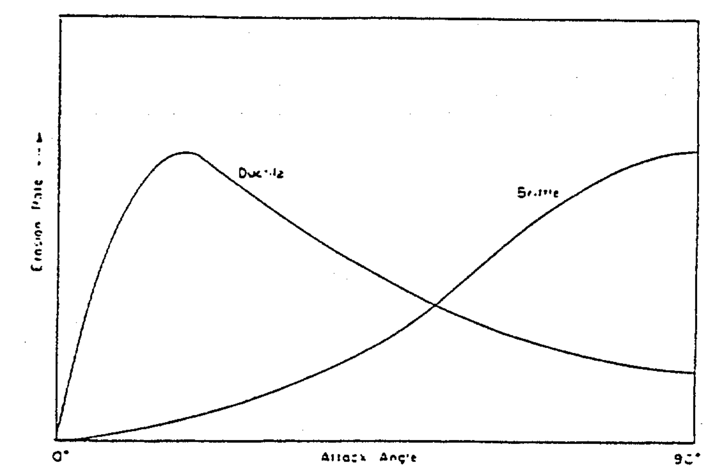

Figure 2: Influence of attack angle on erosion rate (from Ives and Ruff 1978)

Goodwin (1969) showed that at a given particle velocity, erosion rate does not increase with increasing particle size above some minimum particle size. Figure 3 depicts the effect of particle size on the erosion rate.

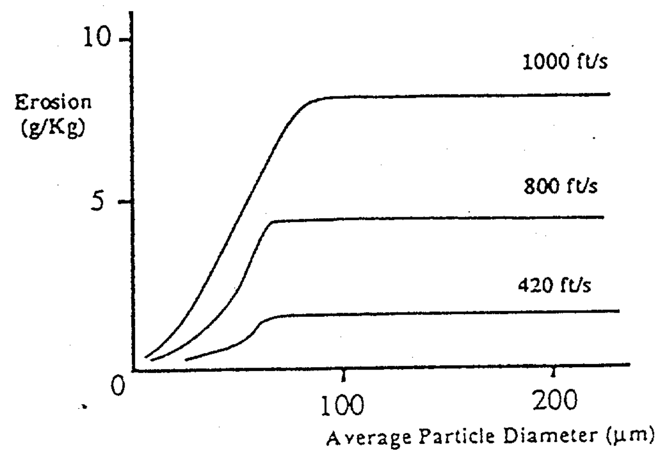

Figure 3: Effect of particle size on specific erosion 11% chromium steel (from Goodwin et. al. 1969)

Previous work conducted at the LSU Petroleum Engineering Research and Technology Transfer Laboratory, experimentally determined the specific erosion factors (F_e) of various fittings affected by abrasives in mud, gas, or mist flows. The fittings evaluated included steel elbows, plugged tees, vortex elbows, and rubber hoses. This work resulted in the development of erosion coefficient correlations for abrasives transported by mud, gas, or mist. A schematic of a model used at LSU for gas-water-sand mixtures is shown in figure 4.

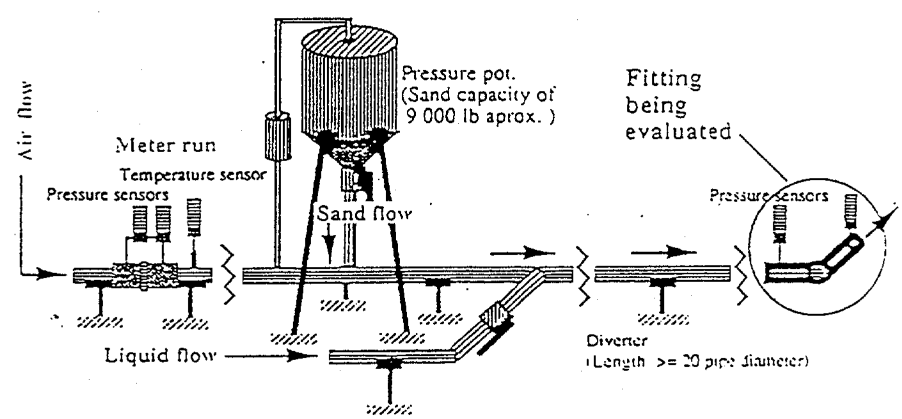

Figure 4: Schematic of a model diverter system for erosion tests

The effect of injecting water directly into the diverted gas flow stream as a means of minimizing the erosion capability of the abrasives contained within the gas flow stream was also studied as part of the previous research work. This work led to the conclusion that water injection does lower the rate of erosion but at the same time increases the pressure at the casing seat. Another finding of the study was that the specific erosion factor is not significantly affected by water content when gas is the continuous phase. It was also observed that external cooling of erosion target zones is not an effective means for reducing the rate of erosion.

Erosion Rate Equation

Based on the previous experimental work carried out at LSU, two equations were proposed for estimating the rate of loss in wall thickness for various fittings; one is recommended for gas and the other for liquid as a continuous fluid carrying abrasive solids.

Dry Gas or Mist Flow

The loss in thickness, h_w, with time, t, of a fitting in a diverter system where gas or mist is the transporting fluid, is given by the following expression in SI units :

$$\frac{dh_w}{dt} = F_e \frac{q_a}{A}[\frac{\rho_a}{\rho_s}][\frac{u_{sg}}{(u_{ref}\lambda_g)}]^2 \quad \text{.... (1a)}$$

where F_e is the specific erosion factor, ρ_s is the density of the diverter system's component, ρ_a is the density of abrasive material, q_a is the flow rate of abrasives , A is area of cross section, u_{sg} is the superficial gas velocity, u_{ref} is a reference velocity of 100 m/s, and λ_g denotes the gas volume fraction.

Liquid Flow

The loss in thickness, h_w, with time, t, of a fitting in a diverter system where liquid is the transporting fluid is given by the following expression in SI units:

$$\frac{dh_w}{dt} = F_e \frac{q_a}{A}[\frac{\rho_a}{\rho_s}][\frac{u_{sl}}{(u_{ref}\lambda_l)}]^2 \quad \text{....(1b)}$$

where u_{sl} is the superficial liquid velocity, and λ_l denotes the liquid volume fraction.

The above equations calculate the erosion rates based on average superficial carrier reference velocity of 100 m/s. We can modify these equations to calculate the erosion rates at sonic velocity of abrasives as :

$$\frac{dh_w}{dt} = F_{ae}\,\frac{q_a}{A}\,[\frac{\rho_a}{\rho_s}] \qquad \text{....(2)}$$

where F_{ae} is the apparent specific erosion factor.

In the previous LSU studies, specific erosion factors of various fittings were determined from experimental data obtained at sub sonic velocities ranging from 32 to 222 m/s. The recent work was performed at sonic velocity of carrier fluid (air in this case) which allowed us to investigate the effect of varying impact angle of abrasive on the erosion rates of flat plates. In addition, the effects of sand grain sizes and sand flow rates on erosion rates were also studied. A comparative study of the erosion rates of various erosion resistant materials was carried out and specific erosion factors (F_e) and apparent specific erosion factors (F_{ae}) for these materials were calculated.

All the previous studies carried out at LSU used common oil field ell and tee fittings made of seamless carbon steel, ASTM-234 grade WPB which was inexpensively available. Since the materials tested in the recent work were expensive, only small size specimens could be used for the tests.

Experimental Equipment and Procedure

The set-up fabricated to carry out the study is shown in figure 5. It consists of an air compressor, a pressure pot for sand injection, a 3/16" critical prover for monitoring gas flow rate, an air pressure regulator, a nominal two inch flow line, and a 1/4" nozzle for maintaining sonic velocity of abrasive stream at the exit.

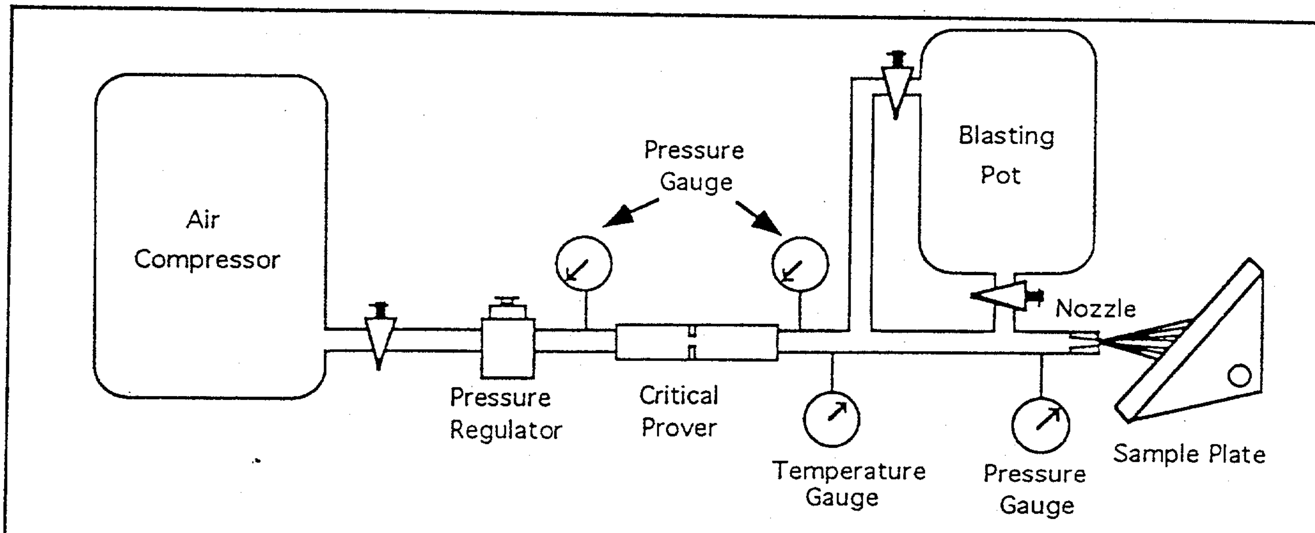

Figure 5: Schematic of experimental set up

In addition to this an experimental set-up was fabricated for varying the angle of impact of abrasive on coupons. For economic and safety reasons, the gaseous fluid used in these experiments was air rather than natural gas. Thus an abrasive mixture of air and sand was used to erode the flat plates. Since the coupons provided by Hydril Inc. were expensive, the experimental set-up was first tested by eroding ASTM A-36 specification steel plates which were readily and inexpensively available. Later on, the tests were carried out on the coupons sent by Hydril Inc.

The experimental set-up and procedure was designed to evaluate the rate of erosion and the specific erosion factor of flat plates at different angles of impact of abrasive. The test matrix that was designed focused on evaluating the effect of:

a) The material selection;
b) Angle of impact; and
c) Sand flow rates.
d) Sand grain size

We maintained air rate at a certain value for all the experimental runs. The weight of the pressure pot was continuously monitored, and sand flow rate was determined from the rate of change in the weight of the pressure pot with time. The mixture of air and sand flowed through a 2" rubber hose and exited through a 1/4" nozzle for five minutes during each run. Weight loss and coupon thickness were determined after the tests. Thickness profiles of the coupons were determined using a dial indicator accurate to 0.001 inch. Grain size distributions of regular blasting sands were measured by sieve analysis. Data were collected to permit evaluation of the effect of change in the angle of impact, sand grain size, sand flow rate, and material type on the erosion rates. Two runs for each set of readings were carried out to check for data reproducibility.

In previous LSU studies, some difficulty was experienced in maintaining a constant sand rate during each test. In this study we were able to maintain sand flow rate at a constant value by installing an orifice in the section of pipe between the blasting pot sand outlet port and the pipe supplying air.

Test Results and Data Analysis

In order to study the effects of the various parameters, specific erosion factor (F_e) and apparent specific erosion factor (F_{ae}) for each run were calculated. Specific erosion factor was obtained as a ratio of loss of weight of the coupon to the mass of abrasives used. The apparent specific erosion factor was calculated from equation (2) proposed for sonic velocity of the abrasive mixtures.

Effect of Angle of Impact on Erosion Rate

The first angle at which the experiment was performed was ninety degrees and the angle was lowered in steps of ten-degrees to fifty degrees. After that, the angles were lowered in steps of five-degrees to twenty degrees. In an effort to find the flow angle at which the observed erosion rate was maximum, additional tests were completed in two-degrees steps between the two tests showing the highest rate of erosion.

Table A1 of the appendix tabulates the test data collected for defining the effect of the impact angle on erosion rates of flat steel plates ASTM A-36 specification. Figure 6 depicts the results in graphical form.

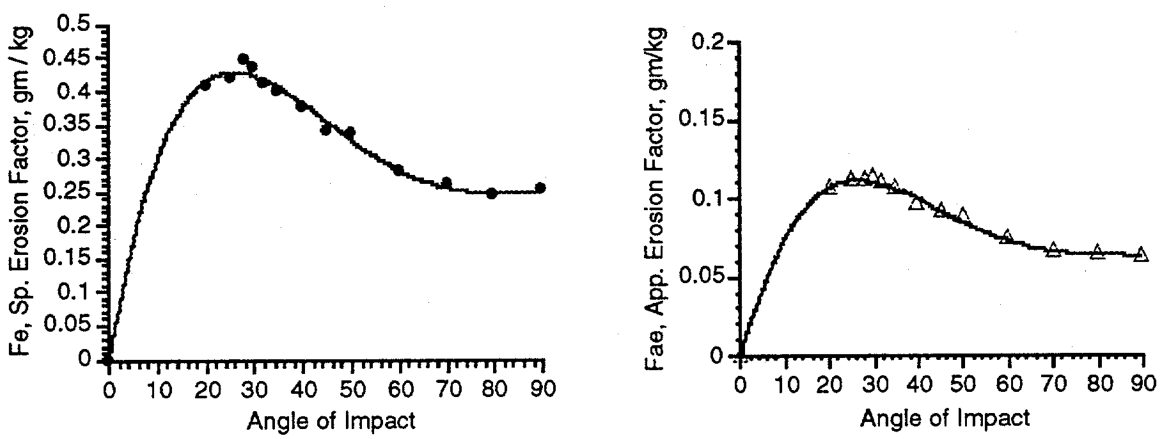

Figure 6: Effect of angle of impact on erosion rate at 1100 ft / sec

As can be observed, the steel plates undergo large erosional losses under glancing angles of impact. Maximum erosion in steel occurred at an impingement angle of thirty degrees. Erosion increases from a ninety-degree angle of impact to thirty degrees. Erosion decreases rapidly for impact angles from thirty degrees through zero degrees. This set of tests shows that the response of steel plates to changes in angles of impact with respect to a stream of high velocity sand particles and air, is typical of ductile materials.

Effect of Sand Rate on Erosion Rate

Different sand flow rates were obtained by installing orifices of different sizes in the section of pipe between the blasting pot sand outlet port and the pipe supplying air. The angle of impact was thirty degrees during this set of runs because maximum erosion was previously observed at this angle. The air flow rate was maintained at 90 scf/min, which was sufficient to produce sonic velocity at the exit. The exit pressure was between 22 and 34 psig over all of the experimental runs.

Table A2 of appendix tabulates the results obtained to define the effect of sand flow rate on erosion. As these results indicate, the wear rate was directly proportional to the sand rate for the range of sand flow rates studied. However, the specific erosion factor shows an inverse relationship to the sand rate. Figure 7 shows the proportional behavior of specific erosion factor with respect to sand rate. Due to limited capabilities of air compressors used, we found it difficult to study the effect of sand flow rate higher than 19 lbs/min. But the sand rates obtained for the tests were sufficient to result in sand concentrations of up to 0.41%, which are acceptable for sand concentrations representative of diverter operating conditions. As the particle concentration in the flow stream increases, the interference between sand grains increases, resulting in the decrease of the specific erosion factor.

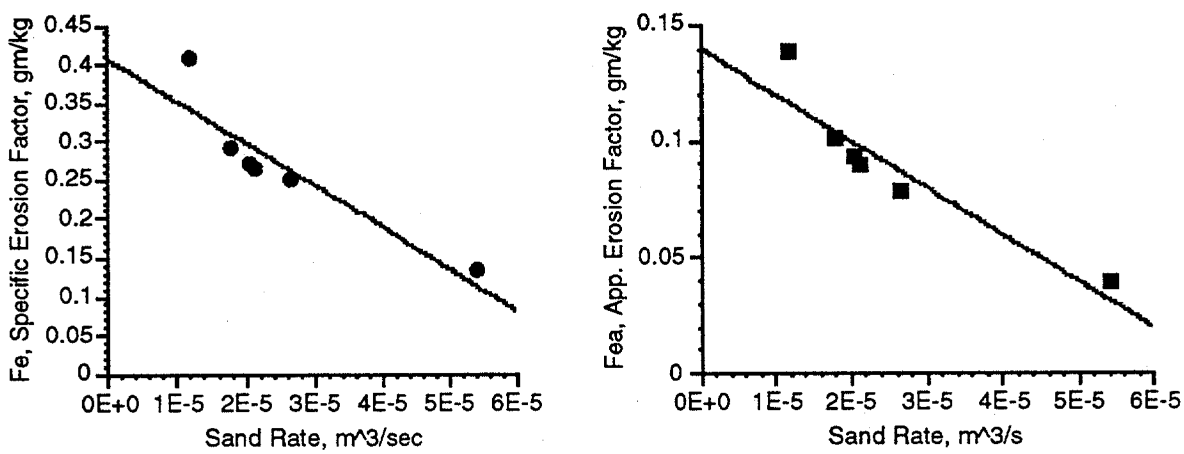

Figure 7: Effect of sand flow rate on erosion rate at 1100 ft / sec

Effect of Sand Grain Size on Erosion Rate

While conducting the tests to study the effects of sand grain size on erosion rate, difficulties were encountered in maintaining constant sand flow rates for different sand grain sizes. In order to keep sand flow rates constant, a series of runs were carried out. Only those observations that had sand rates in the range of 7.125 lbs/min ± 10 % were taken into consideration.

Contrary to the results of studies by Goodwin (1969), impact of sand grain size of 74 µm (US mesh # 200) resulted in higher erosion rate than that of sand grain size of 177-124 µm (US mesh # 80-120). Erosion rates for sand of 1190-420 µm (US mesh # 16-40) and 500-177 µm (US # 35-80) showed almost the same value of specific erosion factors. To ensure the repeatability of the results, a second series of runs was carried out and similar results were observed.

Table A3 of appendix tabulates the results obtained during the tests for studying the effect of sand grain size on erosion rate. These results are shown graphically in figure 8.

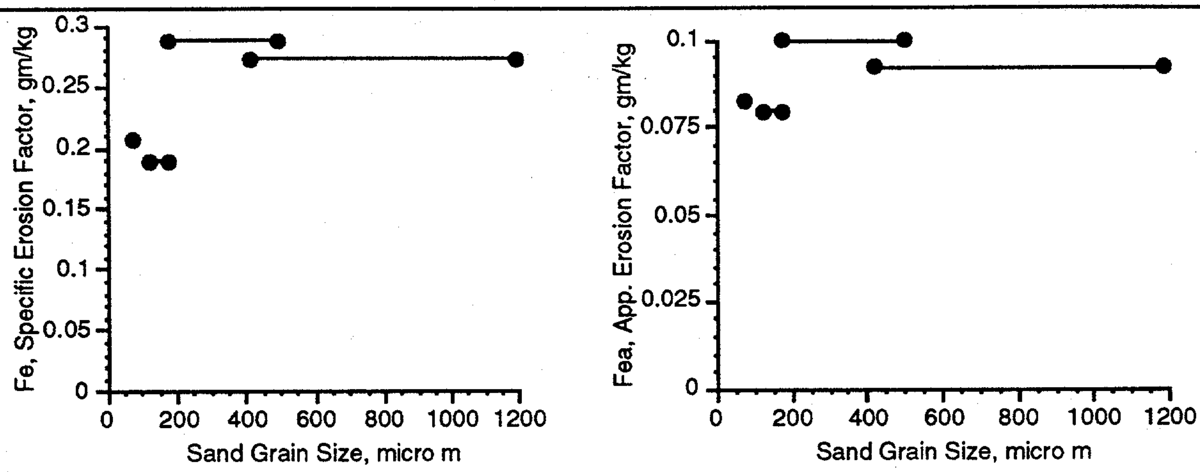

Figure 8: Effect of sand grain size on erosion rate at 1100 ft / sec

Effect of Nozzle Distance from Target on Erosion Rate

In an effort to study the effect of nozzle distance from target, distances between the nozzle and flat plates were varied from zero to three inches keeping the angle of impingement at thirty degrees, air flow rate at 91 scf/min, and sand flow rate at about 4.15 lbs/min.

As the distance between the nozzle and the flat plate was increased from zero to about 1.5 inches, the erosion rate showed an increase since the interference between sand particles decreases. It was also observed that the erosion rate decreased if the distance between the nozzle and the flat plate increased further than 1.5 inches due to reduced impacting velocity of sand particles. The results of these experiments are tabulated in table A4 of appendix.

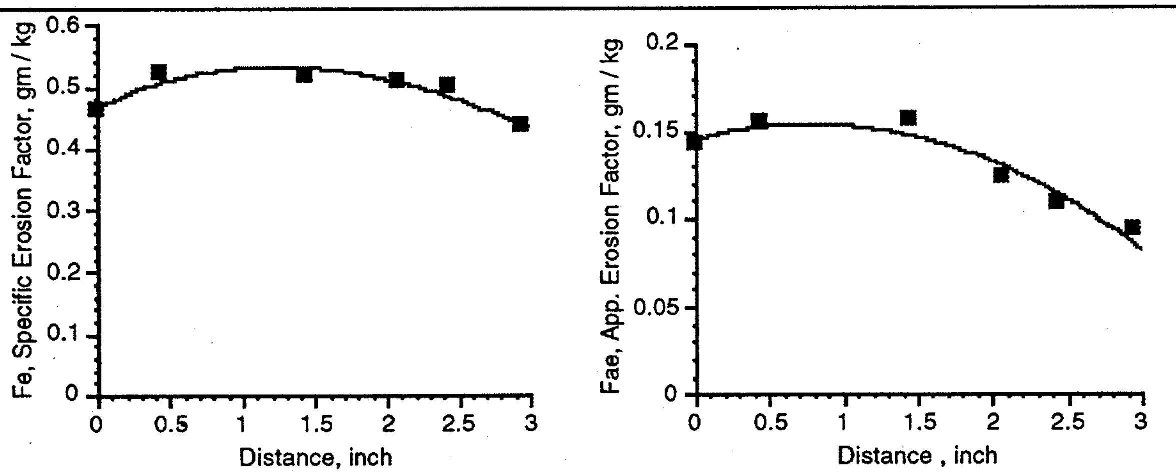

Figure 9: Effect of varying distance between nozzle and plate on erosion rate at1100 ft / sec

Comparison of Erosion Rates of Erosion Resistant Materials

Experiments conducted previously by Bitter (1963 a and b) and Ives and Ruff (1978) showed that ductile materials exhibit maximum erosion rate at impact angles between 20-30 degrees, while brittle materials are least erosion resistant in the vicinity of 90 degrees of the impact angle. In order to differentiate the erosion resistant materials tested in our experimental runs by their degrees of ductility or brittleness, it was decided to carry out tests at the impact angles of ninety degrees and thirty degrees.

In order to facilitate the graphical representation of the results, the materials tested are designated by alphabetical letters as :

Gas metal arc pulse welding of UNS N 06625 alloy	→	GMNi
Submerged arc welding of UNS N 06625 alloy	→	SArNi
Low carbon stainless steel (UNS S 30603 alloy)	→	LCSS
Stellite 21 K	→	ST21K
Stellite 6 K	→	ST6K
Low carbon steel A-36 specification	→	LCS36

a) At Thirty Degrees of Impact Angle

The angle of impact was changed to thirty degrees keeping the air flow rate at about 90 scf/min. The sand grain size used for blasting the coupons was 300 μm (US mesh # 16-40). It was observed that the submerged arc welding coupon of UNS N 06625 alloy was least resistant to erosion while Stellite 6 K coupon showed the maximum resistance in comparison to other materials tested. Figure 10 shows the apparent specific erosion factors of different materials at thirty degrees of impact angle and US mesh # 80-120 sand which is representative size of sand coming out from a blowing well at sonic velocity at diverter exit.

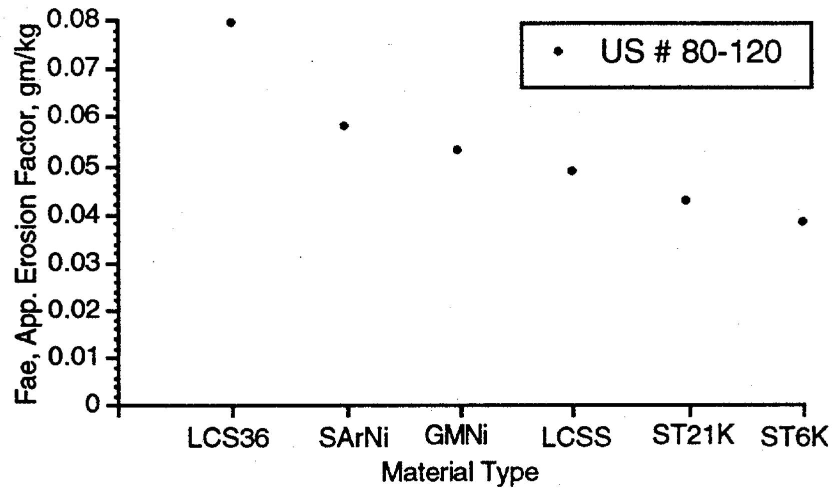

Figure 10: Effect of sand grain size on specific erosion factor of coupons at an impact angle of thirty degrees

This general trend, as shown in figure 11, was also evident when the experimental runs were carried out with sand grain sizes of US mesh # 16-40 and 35-80. Thus, apparent erosion factors of different materials are independent of the sand grain sizes used. Table A5 tabulates the results of the experiments conducted to study this effect.

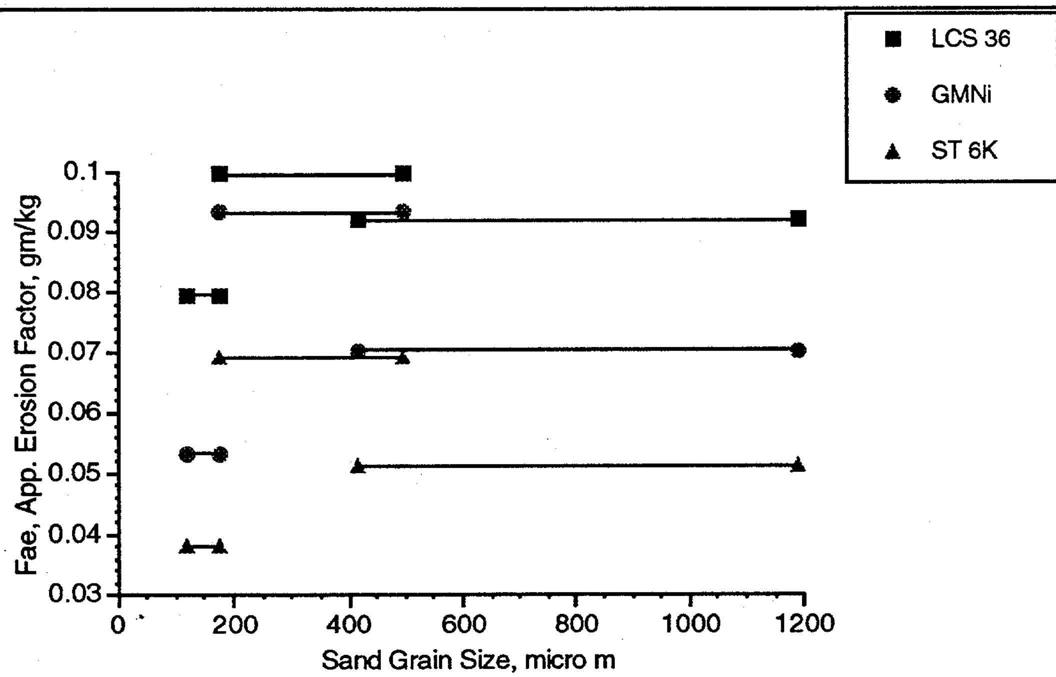

Figure 11: Effect of sand grain sizes on erosion rates of three materials at thirty degrees of impact angle

Data show that stellite 6K coating on a component used to make a bend in a diverter would result in increasing its life by almost 100% over a component made of low carbon steel A-36 specifications, when blasted with sand of US mesh # 80-120 (177-124 μm).

b) At Ninety Degrees of Impact Angle

The angle was changed to ninety degrees keeping the air flow rate at about 90 scf/min. It was noticed that low carbon steel A-36 specification showed the highest erosion rate for sand grain size of US mesh # 16-40 (1190-420 μm). If the erosion behavior of various materials to the sand grain size of US mesh # 80-120 (which is representative of sand size from a blowing well) is analyzed, it is observed that submerged arc welding of UNS N 06625 alloy has the maximum while gas metal arc pulse welding of UNS N 06625 alloy has the least erosion rate. This trend, although not well defined, was also evident when the experimental runs were carried out with sand grain sizes of US mesh # 35-80 (500-177 μm) and # 16-40 (1190-420 μm). Similar results were observed when the coupons were blasted at two different sand flow rates suggesting that this behavior is independent of the sand flow rates.

The results are tabulated in table A6 of the appendix. Figures 12 shows that the erosion rates of all the materials tested were less at ninety degrees than at thirty degrees of impact angle suggesting that problem of erosion failure would be more pronounced for all these materials at thirty degrees of impact rather than ninety degrees.

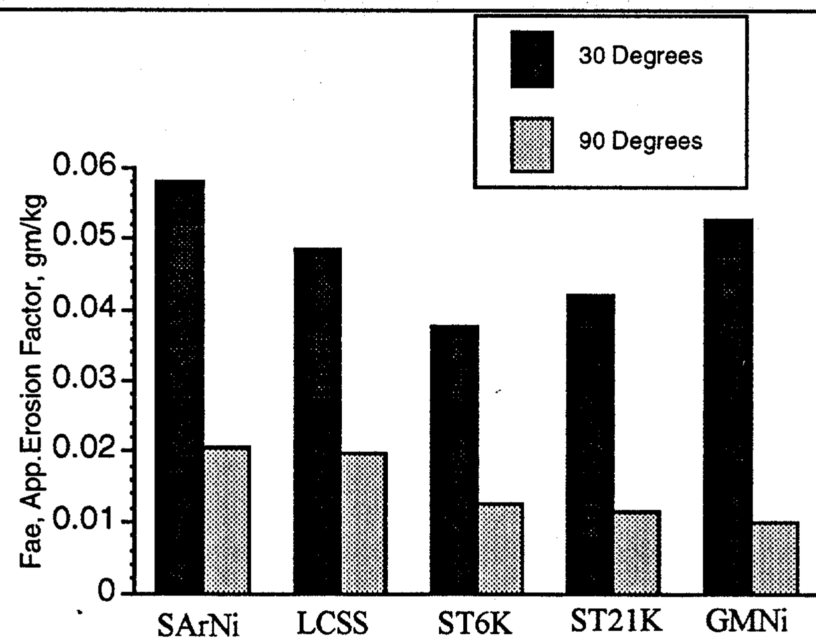

Figure 12: Erosion behavior of different materials for sand grain size of US mesh # 80-120

Summary and Conclusions

Experimental data were obtained for studying the effects of angle of impact, sand grain size, and sand flow rate on the erosion rates of low carbon steel A-36 specification plate at sonic velocity of the carrier fluid (air in this case). Experiments were also conducted to make a comparative study of the erosion rates of the erosion resistant materials provided by Hydril, Inc. for sand grain size of US mesh # 80-120.

The conclusions drawn from this study are:

1. Erosion in diverters can be eliminated to a large extent by avoiding bends in the diverter components but these bends in the diverter lines are often unavoidable. It was observed that erosion is a bigger problem at thirty degrees of impact angle than at ninety degrees. Therefore, fittings like plugged tees should be preferred to short radius ells or elbows whereever possible.

2. At thirty degrees of impact angle and sonic velocity at the diverter exit, life of a diverter bend could be increased by almost 100% if it is coated with stellite 6K than with low carbon steel A-36 specification.

3. The erosion resistant materials in the increasing order of erosion rates at thirty degrees of impact angle (long radius ells or elbows with thirty degrees of change in angle) are:

a) Stellite 6 K,
b) Stellite 21 K,
c) Low carbon stainless steel (UNS S 30603),
d) Gas metal arc pulse welding of UNS N 06625 alloy,
e) Submerged arc welding of UNS N 06625 alloy. and
f) Low carbon steel A-36 specification.

4. The erosion resistant materials again in the increasing order of erosion rates at ninety degrees of impact angle (L bends or plugged tees) are:

a) Gas metal arc pulse welding of UNS N 06625 alloy
b) Stellite 21 K,
c) Stellite 6 K,
d) Low carbon stainless steel (UNS S 30603),
e) Submerged arc welding of UNS N 06625 alloy, and
f) Low carbon steel A-36 specification.

5. Erosion rates of steel plate were maximum at thirty degrees of angle of impact. The rate decreased as the angle of impact was increased to ninety degrees.

6. Wear rate increased while specific erosion factor and apparent specific erosion factor decreased with increase in sand concentration in the flow stream.

Acknowledgments

The authors wish to express thanks to Mr. Joe Roche and Mr. R.P. Badrak of Hydril Incorporation for assisting in selecting materials for testing and providing samples.

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Nomenclature

A	-	Cross sectional area, m^2
f_g	-	Fractional volume of gas
F_e	-	Specific erosion factor, gm/kg
F_{ae}	-	Apparent erosion factor, gm/kg
h_w	-	Thickness, m
q_a	-	Flow rate of abrasives, m^3/s
u_{sg}	-	Superficial gas velocity, m/s
u_{sl}	-	Superficial liquid velocity, m/s
ρ_a	-	Density of abrasives, kg/m^3
ρ_s	-	Density of steel or wall material, kg/m^3
t	-	Time, s

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APPENDIX

Table A1 : Effect of Angle of Impact on Specific Erosion Factor

Material : Steel Flat Plate ASTM-A36 Specification
Sand Grain Size # 16-40 mesh
Air Pressure Upstream of Critical Prover : 90 psig

Angle of Impact	Sand Flow Rate (m^3/sec)	Air Flow Rate (m^3/sec)	F_a	Specific Erosion Factor (gm/kg)	Observed Erosion Rate (in/min)	Apparent Specific Erosion Factor (gm/kg)
90	9.927 E-06	0.01896	0.9994767	0.25213	0.0234	0.0629
80	1.038 E-05	0.01920	0.9994595	0.24468	0.0240	0.0640
70	1.009 E-05	0.01954	0.9994835	0.26032	0.0322	0.0661
60	1.038 E-05	0.01930	0.9994624	0.28224	0.0388	0.0737
50	1.027 E-05	0.01937	0.9994701	0.33681	0.0394	0.0870
45	1.067 E-05	0.01947	0.9994525	0.34071	0.0410	0.0914
40	1.009 E-05	0.01947	0.9994817	0.37615	0.0410	0.0955
35	1.061 E-05	0.01933	0.9994515	0.40062	0.0432	0.1069
32	1.049 E-05	0.01872	0.9994396	0.41336	0.0447	0.1092
30	1.027 E-05	0.01933	0.9994691	0.43602	0.0470	0.1126
28	9.870 E-06	0.01906	0.9994825	0.44729	0.0370	0.1111
25	1.044 E-05	0.01886	0.9994467	0.42164	0.0328	0.1107
20	1.038 E-05	0.01954	0.9994690	0.40821	0.0260	0.1066

Table A2 : Effect of Sand Flow Rate on Specific Erosion Factor

Material : Steel Flat Plate ASTM-A36 Specification
Sand Grain Size # 16-40 mesh
Air Pressure Upstream of Critical Prover : 90 psig

Angle of Impact	Sand Flow Rate (m^3/sec)	Air Flow Rate (m^3/sec)	F_a	Specific Erosion Factor (gm/kg)	Observed Erosion Rate (in/min)	Apparent Specific Erosion Factor (gm/kg)
30	5.434 E-05	0.01377	0.9960704	0.13007	0.0524	0.03832
30	2.687 E-05	0.01745	0.9984625	0.24901	0.0520	0.07692
30	2.139 E-05	0.01809	0.9988187	0.26219	0.0476	0.08843
30	2.065 E-05	0.01702	0.9987880	0.26978	0.0476	0.09161
30	1.820 E-05	0.01782	0.9989801	0.29025	0.0460	0.10046
30	1.192 E-05	0.01831	0.9993493	0.40610	0.0412	0.13734

Table A3 : Effect of Sand Grain Size on Specific Erosion Factor

Material : Steel Flat Plate ASTM-A36 Specification
Angle of Impact : 30 Degrees
Air Pressure at Upstream of Critical Prover : 90 psig

Sand Grain Size (Mesh #)	Sand Flow Rate (m^3/sec)	Air Flow Rate (m^3/sec)	F_a	Specific Erosion Factor (gm/kg)	Observed Erosion Rate (in/min)	Apparent Specific Erosion Factor (gm/kg)
16-40	2.065 E-05	0.01702	0.998788	0.26978	0.0476	0.09161
35-80	2.008 E-05	0.01845	0.998913	0.28559	0.0496	0.09929
80-120	2.002 E-05	0.01773	0.998872	0.18591	0.0392	0.07900
200	2.225 E-05	0.01805	0.998769	0.20350	0.0450	0.08193

Table A4 : Effect of Varying Distance Between Nozzle and Target on Specific Erosion Factor

Material : Steel Flat Plate ASTM-A36 Specification
Angle of Impact : 30 Degrees
Air Pressure at Upstream of Critical Prover : 90 psig
Sand Grain Size # 16-40 mesh

Distance of Nozzle from Target (inches)	Sand Flow Rate (m^3/sec)	Air Flow Rate (m^3/sec)	F_a	Specific Erosion Factor (gm/kg)	Observed Erosion Rate (in/min)	Apparent Specific Erosion Factor (gm/kg)
0	1.169 E-05	0.019407	0.9993976	0.46242	0.0420	0.14274
0.433	1.152 E-05	0.019202	0.9994001	0.52386	0.0450	0.15521
1.432	1.198 E-05	0.019474	0.9993851	0.51650	0.0472	0.15659
2.057	1.181 E-05	0.019133	0.9993831	0.51014	0.0366	0.12318
2.432	1.169 E-05	0.019474	0.9993998	0.49898	0.0318	0.10807
2.932	1.169 E-05	0.018989	0.9993844	0.43446	0.0272	0.09244

Table A5 : Comparison of Specific Erosion Factors of Erosion Resistant Materials at Thirty Degree Angle of Impact

Material : Erosion Resistant Coupons
Sand Grain Size # 16-40 mesh

Coupon	Sand Flow Rate (m^3/sec)	Air Flow Rate (m^3/sec)	F_α	Specific Erosion Factor (gm/kg)	Observed Erosion Rate (in/min)	Apparent Specific Erosion Factor (gm/kg)
LC36	2.065 E-05	0.01702	0.998788	0.26978	0.0476	0.09161
SArNi	2.487 E-05	0.01961	0.9987335	0.29327	0.0410	0.06551
GMNi	2.487 E-05	0.01982	0.9987465	0.27557	0.0436	0.06967
LCSS	2.493 E-05	0.01858	0.9986603	0.26233	0.0378	0.06026
ST21K	2.350 E-05	0.01879	0.9987506	0.27771	0.0352	0.05952
ST6K	2.407 E-05	0.01880	0.9987245	0.23717	0.0308	0.05085

Material : Erosion Resistant Coupons
Sand Grain Size # 35-80 mesh

Coupon	Sand Flow Rate (m^3/sec)	Air Flow Rate (m^3/sec)	F_α	Specific Erosion Factor (gm/kg)	Observed Erosion Rate (in/min)	Apparent Specific Erosion Factor (gm/kg)
LC36	2.008 E-05	0.01845	0.9989130	0.28559	0.0476	0.09929
SArNi	1.957 E-05	0.01926	0.9989853	0.40042	0.0512	0.10400
GMNi	1.934 E-05	0.01906	0.9989865	0.38043	0.0452	0.09289
LCSS	1.939 E-05	0.01996	0.9990294	0.33457	0.0644	0.13196
ST21K	1.917 E-05	0.01989	0.9990374	0.32871	0.0250	0.05183
ST6K	1.751 E-05	0.01989	0.9991202	0.34971	0.0304	0.06899

Material : Erosion Resistant Coupons
Sand Grain Size # 80-120 mesh

Coupon	Sand Flow Rate (m^3/sec)	Air Flow Rate (m^3/sec)	F_α	Specific Erosion Factor (gm/kg)	Observed Erosion Rate (in/min)	Apparent Specific Erosion Factor (gm/kg)
LCS36	2.002 E-05	0.01773	0.998872	0.18591	0.0392	0.07900
SArNi	2.088 E-05	0.01870	0.9988846	0.20841	0.0300	0.05798
GMNi	2.071 E-05	0.01820	0.9988634	0.20102	0.0270	0.05261
LCSS	2.031 E-05	0.01815	0.9988824	0.17339	0.0244	0.04848
ST21K	2.099 E-05	0.01818	0.9988499	0.19282	0.0220	0.04240
ST6K	2.100 E-05	0.01818	0.9988468	0.17253	0.0196	0.03767

Table A6 : Comparison of Specific Erosion Factors of Erosion Resistant Materials at Ninety Degrees of Impact Angle

Material : Erosion Resistant Coupons
Sand Grain Size # 16-40 mesh

Coupon	Sand Flow Rate (m^3/sec)	Air Flow Rate (m^3/sec)	Fa	Specific Erosion Factor (gm/kg)	Observed Erosion Rate (in/min)	Apparent Specific Erosion Factor (gm/kg)
LC36	9.927 E-05	0.01896	0.9994767	0.25213	0.0330	0.0629
SArNi	2.447 E-05	0.01899	0.9987132	0.14645	0.0240	0.03397
LCSS	2.396 E-05	0.01926	0.9987578	0.20156	0.0330	0.05474
ST6K	2.419 E-05	0.01926	0.9987460	0.15390	0.0148	0.02431
ST21K	2.476 E-05	0.01906	0.9987029	0.16407	0.0222	0.03563
GMNi	2.265 E-05	0.01913	0.9988176	0.22212	0.0256	0.04429

Material : Erosion Resistant Coupons
Sand Grain Size # 35-80 mesh

Coupon	Sand Flow Rate (m^3/sec)	Air Flow Rate (m^3/sec)	Fa	Specific Erosion Factor (gm/kg)	Observed Erosion Rate (in/min)	Apparent Specific Erosion Factor (gm/kg)
SArNi	1.934 E-05	0.01954	0.9990113	0.14307	0.0180	0.03699
LCSS	1.900 E-05	0.03816	0.9995025	0.24561	0.0292	0.06109
ST6K	1.774 E-05	0.01920	0.9990768	0.19706	0.0170	0.03808
ST21K	1.785 E-05	0.01947	0.9990839	0.21904	0.0220	0.04897
GMNi	1.911 E-05	0.01947	0.9990195	0.19413	0.0176	0.03666

Material : Erosion Resistant Coupons
Sand Grain Size # 80-120 mesh

Coupon	Sand Flow Rate (m^3/sec)	Air Flow Rate (m^3/sec)	Fa	Specific Erosion Factor (gm/kg)	Observed Erosion Rate (in/min)	Apparent Specific Erosion Factor (gm/kg)
SArNi	1.957 E-05	0.01771	0.9988964	0.06813	0.0100	0.02062
LCSS	2.082 E-05	0.01852	0.9988768	0.09241	0.0102	0.01976
ST6K	2.065 E-05	0.01821	0.9988675	0.07186	0.0064	0.01250
ST21K	2.099 E-05	0.01852	0.9988676	0.07787	0.0060	0.01153
GMNi	1.997 E-05	0.01870	0.9989333	0.07999	0.0050	0.01010

Use of Soil Borings Data for Estimating Break-Down Pressure of Upper Marine Sediments

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Abstract

This paper illustrates how soil borings data was used to determine the formation break-down pressure for the Green Canyon area of the Gulf of Mexico. Example soil borings data are integrated with deeper well log data to more accurately estimate overburden stress. Soil borings data also gives insight into the geotechnical plasticity of these sediments. This plastic nature affects the horizontal-to-vertical effective stress ratio. Values for the horizontal-to-vertical effective stress ratio are confirmed by measuring the actual in-situ formation breakdown pressure while collecting the soil samples. This study demonstrates that upper marine clays behave plastically with horizontal-to-vertical stress ratios of about 1.0 rather than the extrapolated value of 0.33 often used for sands.

The current objectives of soil-boring geotechnical studies is for designing platform foundations. This study recommends that soil-boring geotechnical studies be extended to include obtaining data for designing shallow-gas well control systems.

1. Importance of the study

There have been numerous disastrous blowouts after encountering an unexpected flow of gas into the well from a shallow formation. By the time the rig crew can recognize the problem and react to it, gas may have already traveled a considerable distance up the open borehole. Closing the blowout preventers may allow the wellbore pressure to build up to a value exceeding the formation breakdown pressure. When this happens, one or more flow paths can travel to the surface or to disturbed soil near a platform leg. In some cases, a crater forms in the seafloor. If the rig structure is bottom supported, the entire rig may be lost.

One current solution to this problem is to divert the flow away from a bottom-supported rig using a diverter system. The diverter system is used to reduce the wellbore pressure so that it does not exceed the formation break-down pressure. However, diverter systems can also lead to crater formations according to a recent study [Rocha and Bourgoyne, 1994] [1] on the mechanisms of sediment failure and crater formation. Crater formation during diversion can occur when shallow unconsolidated water sands are present. Water production from shallow aquifers can carry large volumes of sand from the reservoir, resulting in the excavation of aquifer sediments near the wellbore. Subsequent collapse of overlying sediments can open a flow path to the surface. Thus, for some sedimentary sequences, diverters cannot insure that cratering will not occur.

The above concerns have led us to re-examine the controlling design parameters for shallow casings in order to determine when shutting-in a shallow kick is technically and economically feasible. A recent paper by Arifun

[1] References at end of paper.

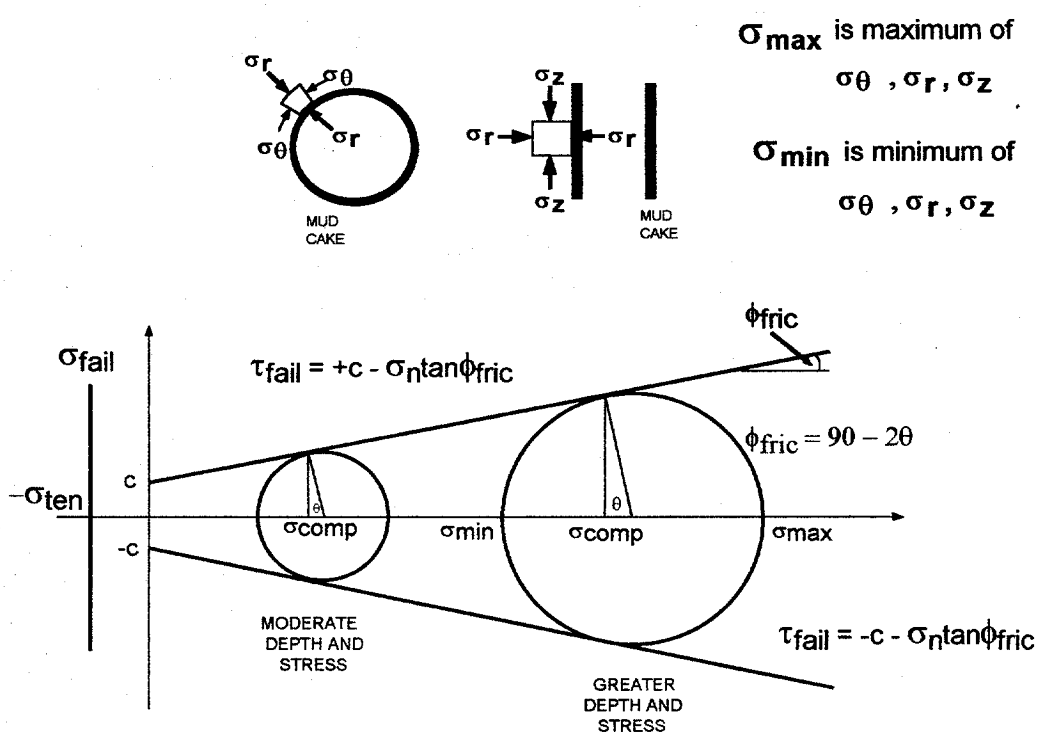


Fig. 1. Mohr-Coulomb Failure Criteria

and Sumpeno (1992) with Unocal Indonesia has indicated that wells are being designed assuming shut-in from surface to total depth in their East Kalimantan operations.

For either shut-in or diverter operations, sediment strength and permeability are key parameters in the design of a shallow casing. In most areas, well log data are not available for the shallow sediments. This paper describes how soil borings can be used to help fill-in some of the missing data needed in designing the shallow portion of the well. Example data from the Green Canyon area of the Gulf of Mexico are used to illustrate the recommended approach. Soil boring data are integrated with deeper well log data to provide a more accurate estimate of overburden stress and formation break-down pressure.

2. Background information

2.1. Review of sediment failure criteria

The effective vertical matrix stress (intergranular pressure) is the most important parameter controlling sediment failure during well control operations. The effective matrix stress is defined by:[2]

[2] Nomenclature and Illustrations at end of paper.

$$\sigma_z = s - p \qquad (1)$$

where s is the total overburden stress and p is the formation pore pressure.

In recent work, Rocha (1993) used a modified Mohr-Coulomb failure criteria (Fig. 1) to help visualize the various sediment failure mechanisms leading to the formation of a crater during well control operations. In Figure 1 the Mohr's Circles are drawn with their center on the abscissa. Minimum and maximum principal effective stresses (σ_{min} and σ_{max}) are also on the abscissa. Sediment failure is predicted to occur whenever a Mohr's Circle touches one of the failure lines given by:

$$\sigma_{fail} = -\sigma_{ten} \qquad (2a)$$

$$\tau_{fail} = \pm c \pm \sigma_n \tan(\phi_{fric}) \qquad (2b)$$

When the Mohr's Circle touches the tensile strength line, σ_{fail}, a hydraulic fracture type failure occurs. This is the usual failure mode during well control operations for deeper sediments, and the hydraulic fracture orientation is generally near vertical.

When the Mohr's Circle touches a shear strength line, τ_{fail}, a shear type failure occurs. The shear failure begins with the formation of numerous micro-cracks which can be followed by linking and propagation of the micro-cracks to form a gouge zone. The reduced tensile strength and increased permeability associated with the formation of microcracks is believed to sometimes cause the shear failure-mode to change to a tensile failure-mode.

Figure 1 indicates that the angle of internal friction is the slope of failure criteria line. Deep unfractured rocks that are well cemented have a high cohesion (shear strength), c, and a high angle of internal friction, ϕ_{fric} of about 30°. In this case, the shear strength and compressive strength increase rapidly as the confining stress is increased with increasing depth. Additionally, tensile strength is usually very low compared to the maximum effective stress, σ_{max}, and compressive strength, σ_{comp}. The tensile strength will be zero if natural fractures are already present. In well design practice, sediment tensile strength is usually assumed to be zero.

Marine sands near the surface that contain little or no clay usually are cohesionless (c = 0) and have no tensile strength (σ_{ten} = 0). Failure of these sediments during an underground blowout can lead to formation liquefaction (fluidization) if the vertical pressure gradient due to flow of formation fluids in the sand reaches or exceeds the static effective vertical stress present prior to the underground blowout.

Shallow marine clays not only have low cohesion and tensile strength, but also have a low angle of internal friction ($\phi \sim 6$ degrees). Shallow formations found in many areas of the Gulf of Mexico are predominantly marine clays. Shallow marine clays tend to behave plastically, making the effective matrix stress in the horizontal direction essentially equal to the vertical matrix stress. In shallow plastic formations, the sediment failure mechanism may not be a true hydraulic fracture. A shear stress failure followed by seepage and tunnelling-type erosion is believed to be a possible mode of failure. Failure modes in which flow through the sediments occurs in pipe-like channels have been documented extensively in the geotechnical literature concerning failure of earthen dams. Exit holes in the seafloor consistent with piping-type channels have also been observed during underground blowouts using remote cameras and divers.

2.2. Stress concentrations around the borehole

The ***initiation*** of sediment failure in a wellbore can occur at a higher pressure than is required for fracture ***propagation.*** To initiate a vertical fracture, horizontal stress concentrations present near the borehole wall must be exceeded. Some of the horizontal stress previously carried by the rock that was removed by the bit must be borne by the remaining rock. Additionally, mud is generally present in the well when sediment

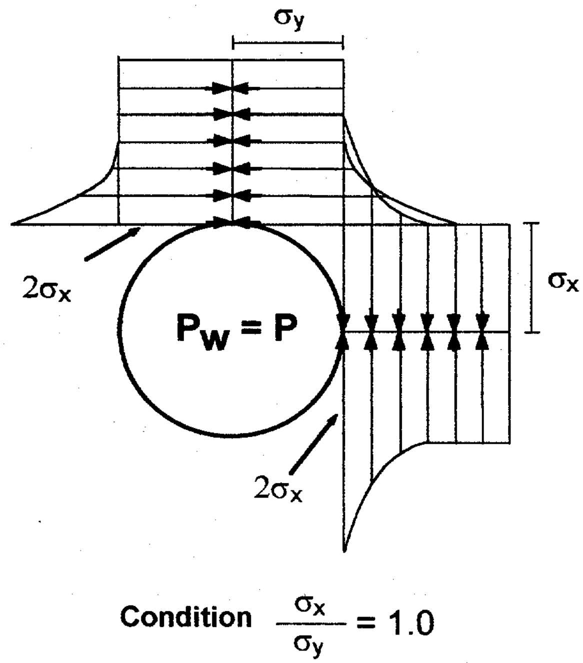


Fig. 2. Stress Concentration Around the Borehole

failure is initiated, and thus permeable zones are always covered by a filter cake. Consequently, the wellbore fluids do not easily penetrate the borehole walls as the pressure is increased above the pore pressure.

Shown in Figure 2 is a plot of the horizontal stress as a function of distance from the wellbore wall for the case of uniform horizontal stress. This calculation was presented by Hubbert and Willis (1957) for the case of elastic rock behavior and a smooth and cylindrical borehole with axis parallel to a principal stress. Note that the stress concentration near the wellbore results in a horizontal effective stress twice that of the undisturbed (far-field) horizontal stress.

The principal stresses present at the borehole wall for a non-penetrating fluid, uniform horizontal stress, and elastic rock behavior are given by [Rocha, 1993]:

$$\sigma_{rw} = p_w - p \quad (3a)$$

$$\sigma_{\theta w} = 2\sigma_h + p - p_w \quad (3b)$$

$$\sigma_{zw} = \sigma_z \quad (3c)$$

Equation (3b) predicts that in order to initiate a vertical hydraulic fracture, the compressive hoop stress at the borehole wall, $\sigma_{\theta w}$, must be reduced to a tensile stress equal to the tensile strength of the rock, σ_{ten}. This occurs if the wellbore pressure increases to the following fracture initiation pressure:

$$p_{init} = p + 2\sigma_h + \sigma_{ten} \quad (4)$$

However, once the hydraulic fracture propagates beyond the area near the borehole wall where the stress concentrations are present, the predicted fracture propagation pressure reduces to:

$$p_{frac} = p + \sigma_h + \sigma_{ten} \quad (5)$$

When natural fractures or flaws already exist in nature, tensile strength can be neglected and stress concentrations have already been penetrated. Thus we have:

$$p_{frac} = p_{init} = p + \sigma_h \quad (6)$$

This situation is assumed to be true in many areas because of the following observations:

(1) significant reductions in pumping pressure is seldom seen after fracture initiation during leak-off tests.

(2) repeated leak-off tests seldom show a decrease in the observed leak-off pressure.

When the vertical effective stress, σ_z, and horizontal effective stress, σ_h, are essentially equal, a horizontal fracture may occur. However, an irregularity in the borehole wall must be either naturally present or started by vertical fracture initiation. The irregularity must be present before a vertical component of force can be applied by the mud pressure to open a horizontal fracture. Weak interfaces at sediment

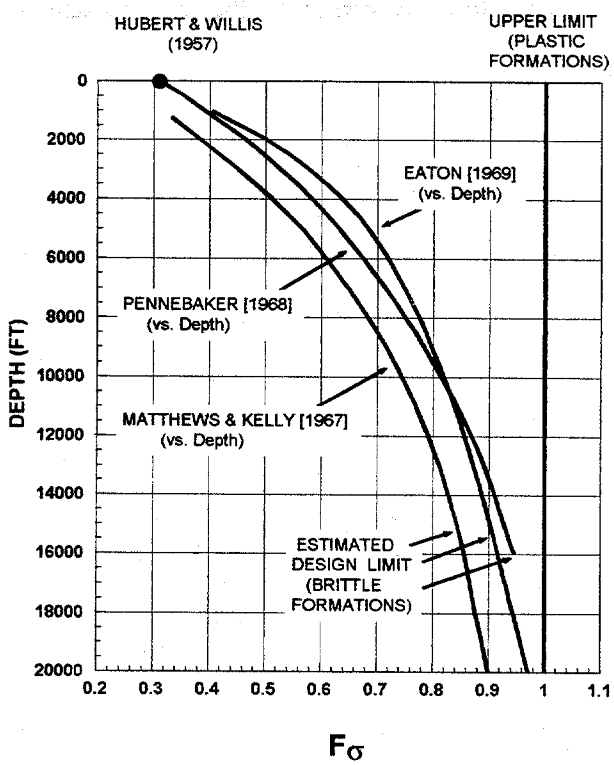


Fig. 3. Ratio of Horizontal Effective Stress to Vertical Effective Stress for the Louisiana Gulf Coast

bedding planes can help promote a horizontal fracture. For a uniform horizontal stress field, vertical stress concentrations would not be present near the borehole, and thus no differential is predicted between fracture initiation pressure and fracture propagation pressure. Equation (6) would apply with $\sigma_h = \sigma_z$.

2.3. Ratio of horizontal to vertical stress

Before fracture pressure can be predicted from Equations (4) - (6), the effective horizontal stress must be estimated. For sediments between the surface casing depth and the total well depth, the most common approach has been to correlate the minimum observed ratio, F_σ, of horizontal-to-vertical effective stress with depth. Leak-off test data and incidents of lost-returns have been used to develop empirical correlations for various geographic areas. The correlations were heavily weighted to represent the weaker sediments found at a given depth so that a conservative estimate of fracture pressure could be predicted for use in well design calculations. Once F_σ is obtained from the empirical correlation, the fracture pressure can be estimated using:

$$p_{frac} = F_\sigma \sigma_z + p = F_\sigma (s - p) + p \qquad (7a)$$

Shown in Figure 3 are several correlations commonly used to estimate the horizontal-to-vertical effective stress ratio for the Louisiana Gulf Coast Area. Note that the ratio decreases for the more shallow sediments and approaches a value of about 0.33 at the surface. Hubert and Willis (1957) determined this value for unconsolidated sands in sand-box experiments conducted in the lab. At deeper depths, the ratio F_σ approaches a value of one as the sediments become more plastic with increasing confining stress.

Extrapolation of the empirical correlations shown in Figure 3 to very shallow depths gives a low value of F_σ ,and thus very low values for shallow fracture pressure are often predicted. In reality, many shallow marine sediments behave plastically, with F_σ values near one. Use of the correlations shown in Figure 3 for these sediments can result in unrealistic formation breakdown pressures being used in the casing design calculations.

Shown in Figure 4 are F_σ values estimated from leak-off tests from 5 wells drilled in the Green Canyon Area, Offshore, Louisiana. Note that the average observed value of the horizontal-to-vertical effective stress ratio ranges from 0.8 to 1.4 and averages about 1. The observed values in excess of 1 are likely due to: (1) experimental errors which occur while running and interpreting the leak-off tests, (2) the presence of stress concentrations in and around the borehole, and (3) the presence of non-zero tensile strengths in the sediments exposed during the test.

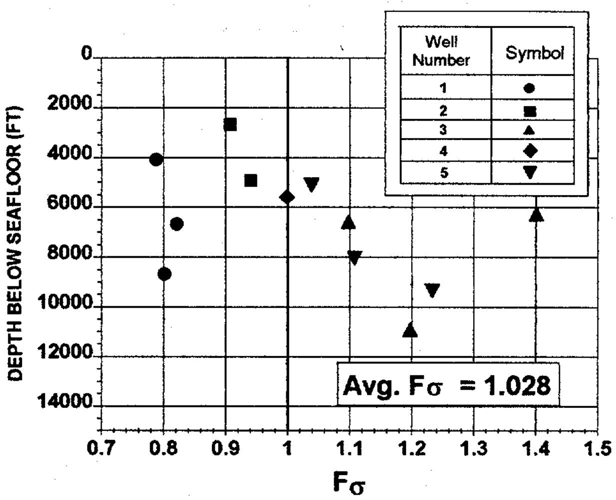


Fig. 4. Ratio of Horizontal to Vertical Effective Stress Determined from Leak-Off Tests in the Green Canyon Area, Offshore Louisiana

2.4. Overburden pressure

The overburden pressure is the most important parameter affecting fracture pressure. The overburden pressure, s, at a certain depth can be thought of as the pressure resulting from the total weight of the rock and pore fluids above that depth. Since bulk density, ρ_b , is a measure of the weight of rock and pore fluids, the overburden pressure at a certain depth can be easily calculated by integration of the bulk density vs. depth profile.

$$s = \int_0^{D_s} \rho_b g dD_s \qquad (8)$$

Thus one method to calculating the overburden pressure is to sum up the average interval bulk density times interval height for all intervals above the depth of interest.

For offshore sediments, hydrostatic pressure due to water depth must also be considered and Equation (8) becomes:

$$s = \int_0^{D_w} \rho_{sw} g dD_w + \int_0^{D_s} \rho_b g dD_s \qquad (9)$$

The best source of bulk density data is from in situ measurements made with a gamma-gamma formation density log. Unfortunately such data is seldom available for depths less than the surface casing setting depth. Accuracy of the formation density logs can be poor in large diameter holes, so that a pilot hole may be required to get good measurements in the shallow sediments. Logging-while-drilling (LWD) tools are now available that can measure formation density, but they also require hole diameters no greater than 14 in. Thus a pilot hole may be required to get accurate density measurements in the upper marine sediments.

Sonic travel times determined from well logs or calculated using seismic data can also be used to estimate the formation bulk density. However, Rocha (1993) found that there was a poor agreement between density values obtained with sonic and density logs in the upper marine sediments. The difficulty stems from uncertainty about the proper choice of matrix travel time values for shallow clay sediments.

Cuttings density data obtained while drilling is sometimes available in the shallow sediments. However, the bulk density of cuttings can be highly altered by the release of confining pressure and by exposure to the drilling fluid.

2.5. Overburden stress as a function of porosity

Because of the problems discussed above, detailed information on bulk density is often not available at shallow depths. Thus density at shallow depths must often be extrapolated from information obtained at deeper depths. This is typically done using porosity instead of bulk density.

Bulk density can be defined in terms of porosity, ϕ, and other variables using the following equation:

$$\rho_b = (1-\phi)\rho_{matrix} + \phi\rho_{fluid} \qquad (10)$$

From the above equation bulk density is primarily dependent on porosity since the other variables of grain matrix density and pore-fluid density usually do not have a wide range of values.

Porosity often decreases exponentially with depth, and thus a plot of porosity vs. depth on semilog paper often yields a good straight-line trend. This exponential relationship can be described using the following equation.

$$\phi = \phi_0 e^{-KD} \qquad (11)$$

The constants ϕ_0 , the surface porosity, and K, the porosity decline constant, are determined graphically or by the least-square fit method. Substituting Equation (11) into Equation (10) gives:

$$\rho_b = +(1-\phi_0 e^{-kD_s})\rho_{matrix} + \phi_0 e^{-kD_s}\rho_{fluid}$$

which after substituting into Equation (9) and integrating, gives

$$s = \rho_{sw} g D_w + \rho_{matrix} g D_s - \frac{(\rho_{matrix} - \rho_{fluid}) g \phi_0}{K}\left(1 - e^{-KD_s}\right) \qquad (12)$$

Rocha, (1994) proposed that most shallow marine sediments found in the gulf coast exist in a plastic state of stress and that F_σ approaches 1 in Equation (7). As the matrix stress coefficient, F_σ , becomes 1.0, the effect of pore pressure vanishes and fracture pressure becomes equal to the overburden pressure.

$$p_{frac} = 1.0\left(s_{pob} - p\right) + p \qquad (7b)$$

Leak-off tests were then used to calculate a pseudo-overburden pressure, s_{pob}, using Equation (7b) . The constants of surface porosity, ϕ_0 , and the porosity decline constant, K , are determined in order to get the best fit of the leak-off test data from Equation (12) for $s = s_{pob}$. Rocha determined values for ϕ_0 and K for several areas in the Gulf Coast and Brazil. These values are given in Table 1.

3. Soil borings tests

A number of tests are routinely run on soil borings by geotechnical engineers to determine the load bearing capacity of the shallow sediments. The physical properties tested generally fall into one of three categories:

1) weight/density measurements,
2) Atterberg limits, and
3) shear strength measurements.

Weight/density measurements include moisture content, wet unit weights, and dry unit weights. Atterberg limits tests measure plastic limits and liquid limits of the soil. Shear strength measurements are done with miniature vane, Torvane, Remote vane, Cone Penetrometer (CPT), and triaxial shear tests.

Tests can also be made of chemical properties such as acid solubility, gas and hydrocarbon content, water salinity, and x-ray analysis. Generally, chemical and x-ray tests are performed in the laboratory.

After being retrieved on the surface but before being extruded from the sample tube, miniature vane tests for shear strength are performed. The sample is then extruded from

Table 1
Values for Surface Porosity and Porosity Decline Constant, Rocha (1993)

Area	ρ_{grain}	ϕ_0	K
Green Canyon	2.65	0.770	323 E-6
Main Pass	2.67	0.590	100 E-6
Ewing Bank	2.65	0.685	115 E-6
Mississippi Canyon	2.65	0.660	166 E-6
Rio de Janeiro Area	2.70	0.670	18 E-6

the sample tube and cut. Representative portions are carefully packaged, sealed, and sent to labs for further testing. The remainder of the sample is tested in the field. Normal field tests are the Atterberg limits tests, visual classifications, and various strength tests. Lab testing includes unconsolidated-undrained tests.

The hole from which the sample was taken can also be tested to obtain in situ values of shear strength, hydraulic fracture pressure, temperature, etc. using specialized tools at the bottom of a drill string.

3.1. Atterberg limits tests

The Swedish scientist, Atterberg, proposed that a soil can exist in one of four possible states -- solid, semisolid, plastic, and liquid -- depending on the moisture content of the soil. The moisture content is defined as the weight of water per unit weight of matrix material. The higher the moisture content, the more fluid the soil becomes. The moisture content at the point of transition from the semisolid state to the plastic state is known as the plastic limit, and from the plastic state to the liquid state is known as the liquid limit. The plastic limit and liquid limit are known as the Atterberg limits and are quantitatively determined by a standardized method developed by Cassagrande (1932).

3.1.1. Liquid Limit

To determine the liquid limit, the soil is placed in a brass cup, and a groove is cut at the center of the soil pat with a standard grooving tool. Next, the cup is lifted and dropped (using a crank-operated cam) from a height of 0.3937 in (10 mm) onto a hard rubber base repeatedly until the soil flow fills 0.5 in. of the bottom of the groove. The test is repeated at least four times for the same soil at varying moisture contents that require from 15 to 35 blows to close the groove. The moisture content, in percent, and the corresponding number of blows are plotted on semilogarithmic graph paper to produce the flow curve. The flow curve is approximately a straight line. The moisture content corresponding to 25 blows is defined as the liquid limit. For moisture contents above this value, the soil is considered to have negligible cohesive strength and behave essentially as a liquid.

3.1.2. Plastic Limit

The plastic limit test is a simple test in which the soil mass is rolled by hand on a ground glass plate from an ellipse into a thread.

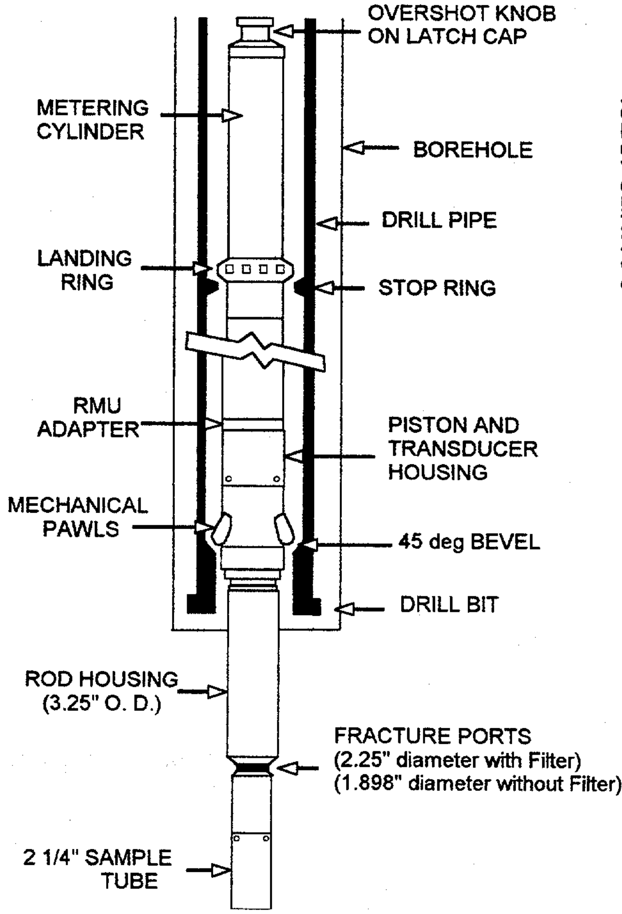
The plastic limit is defined as the moisture content, in percent, at which the soil crumbles when rolled into 1/8 in. (3.2 mm) diameter thread. For moisture contents below this value, the soil would behave more like a semisolid, but still would have a non-linear (concave downward) stress-strain relationship.

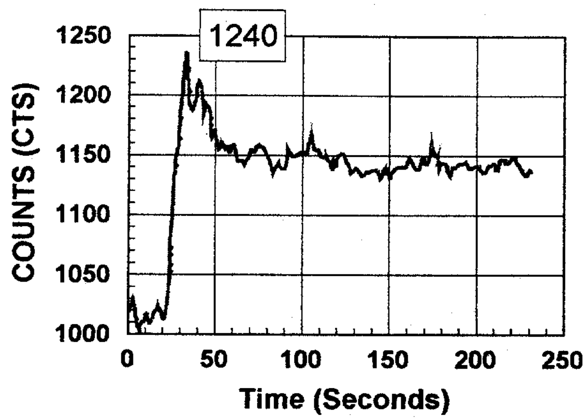
The liquidity index is the ratio of the difference between the in-situ moisture content and the plastic limit to the difference between the liquid limit and plastic limit. If the liquidity index is greater than 1, the sediments can be transformed into a viscous form to flow like a liquid. A liquidity index greater than one implies the presence of sensitive clays and behavior somewhat similar to a drilling mud with a high gel strength. A liquidity index less than one implies some degree of consolidation and a liquidity index less than zero implies over-consolidation. The liquidity index is zero when the soil is at the boundary between a plastic and a semi-solid.

3.2. Shear strength tests

3.2.1. Vane Tests

Undrained shear strength, c_u, of very plastic cohesive soils may be obtained directly from vane tests. The shear vane usually consists of 4 thin, equal-sized steel plates welded to a steel torque rod. The vane is pushed into the soil and then torque is applied to rotate the vane at a uniform speed. The required torque is read from a torsion indicator. In conducting a field vane





Test Depth: 260'
Water Depth: 1749'
Calculated Hydrostatic: 893 psi
Calibration Factor: 0.7245 psi/cts
Transducer Offset: -121 cts
Scale Offset: 1000 cts
Scale Factor: 5
Peak Counts: 1240 cts
Fracture Pressure: 999.7 psi = 144 ksf

Fig. 5. Schematic of Wireline Retrievable Hydraulic Fracture Tool
(Courtesy of Fugro-McClelland Marine Geosciences, Inc.)

test, the vane is rotated at approximately 6 degrees per minute. The undrained cohesion, c_u, determined from vane shear test is a function of clay type and the angular rotation of the vane.

3.2.2. Torvane

The Torvane is hand-held device with a calibrated spring used to determine the undrained cohesion, c_u , for the tube specimens. The Torvane can be used in the field and in the lab. The Torvane is pushed into the soil and then rotated until the soil fails. The undrained shear strength is read from a calibrated dial.

3.2.3. Miniature Vane

The miniature vane is a smaller version of the Torvane. Miniature vane tests are done on the retrieved sample before being extruded from the sample tube.

3.2.4. Cone Penetrometer Test (CPT)

Penetrometers consists of a rod with a cone shaped tip which is pushed into the soil at a standard rate while recording the required force. The test can be run in situ at the bottom of a drill string with the data stored in a downhole memory unit. Data is down-loaded from the unit after it is retrieved by wire line.

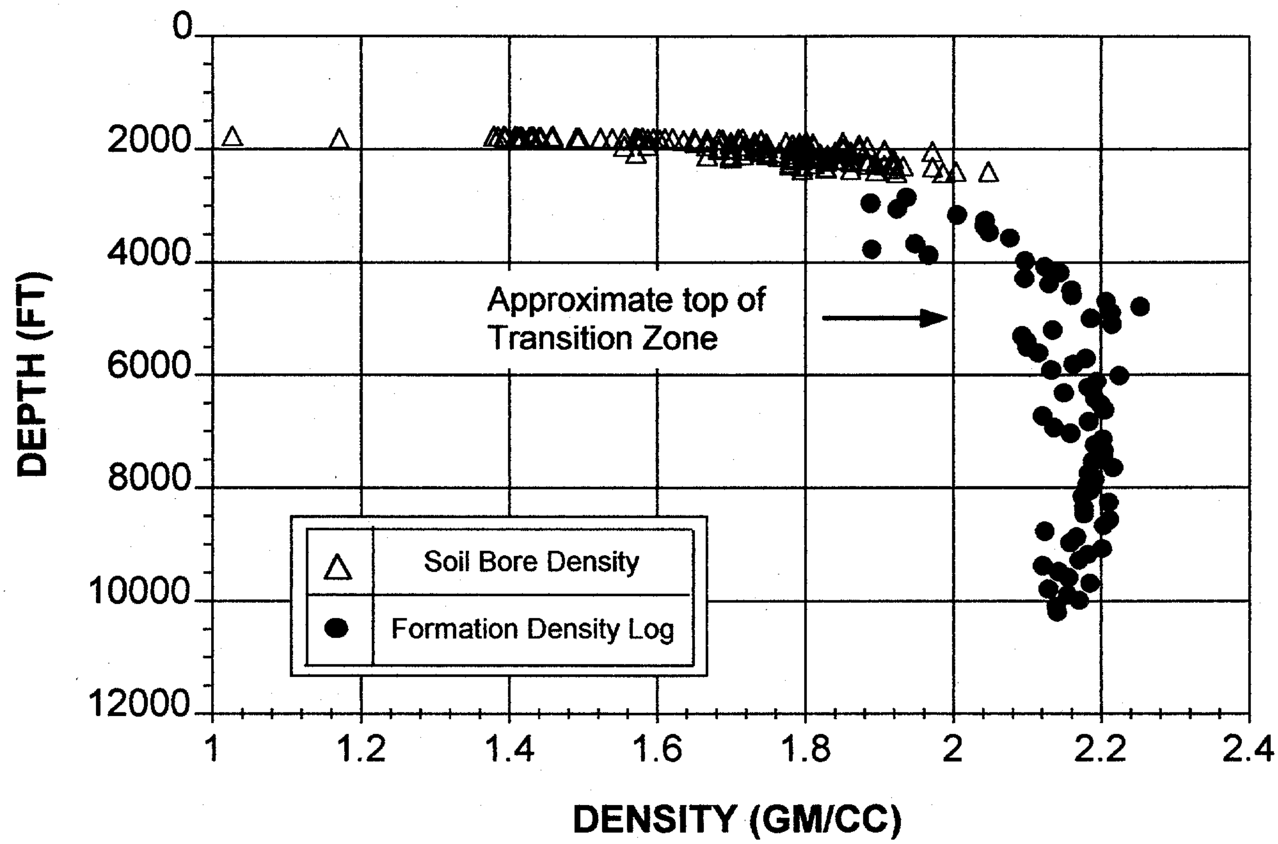


Fig. 6. Sediment Bulk Density versus Depth for the Green Canyon Example

3.2.5. Triaxial Shear Test

In this test, the soil sample [about 1.5 in (38.1 mm) in diameter and 3 in (76.2 mm) in length] is encased within a thin rubber membrane and placed inside a cylindrical chamber filled with water or glycerin. Pressure applied to the water or glycerin is transferred to the soil sample. The soil sample is then sheared with a vertical loading ram. Drainage in or out of the soil sample and pore pressure can also be measured.

3.2.6. Unconsolidated-Undrained Test

In unconsolidated-undrained tests, drainage from the soil specimen is not permitted either during the application of chamber pressure or during the shear failure of the specimen. Since drainage is not allowed at any stage, the test can be performed very quickly.

The test is usually conducted on clay specimens because in saturated cohesive soils, axial stress at failure is practically constant regardless of the chamber confining pressure.

3.3. Hydraulic fracture pressure

The hydraulic fracture test can be performed in situ using a wireline retrievable unit (Figure 5) similar to the cone penetrometer test unit. Soil samples are removed from the test hole with a 2.25-in. O.D. thin walled tube. The wall thickness of the tube is about one-sixteenth of an inch to minimize disturbance and lateral compression of the sediments. An extension rod pushes the sampler cylinder into the bottom of the hole and at the same time packs-off a portion of the annulus above the sampler and outside the extension rod. Fluid is injected into the packed-off annular cavity at a constant rate of about 0.5 gal/min while recording the injection pressure.

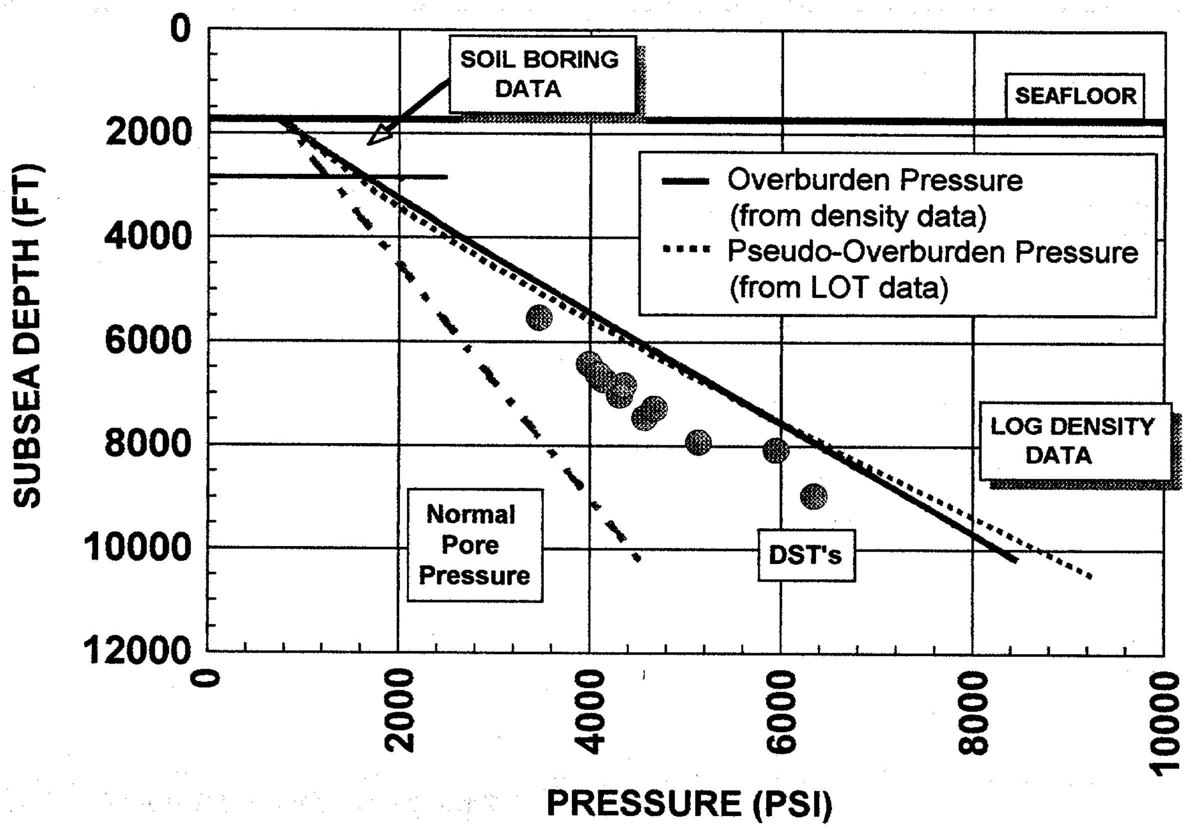


Fig. 7. Overburden Pressure and Pore Pressure versus Depth for the Green Canyon Example

A record of the injection pressure versus time is stored in the unit and then down-loaded after the unit is brought to the surface. The unit is pulled from the sediments using the drill-pipe and once free can be retrieved by wireline.

4. Example results

The most important parameter needed to estimate sediment failure during shallow gas well control operations is the formation bulk density versus depth profile. Shown in Figure 6 is a composite density versus depth profile for a prospect in the Green Canyon area. The lower portion of the profile (circles) was obtained from a formation density log run in a nearby well. The upper portion of the profile (triangles) was obtained from wet unit weight data collected from soil borings. Integration of this profile produced the overburden pressure versus depth curve shown in Figure 7.

Shown in Figure 8 are plots of moisture content, liquidity index, and shear strength versus depth. Also shown is a lithology description. These data show that the sediments penetrated by the soil borings are impermeable (only clay was found) and that the sediments are plastic. The clays are classified as very soft to soft, and the liquidity index dropped below zero only for a small interval near the bottom of the interval penetrated. This indicates the ratio of horizontal to vertical effective stress would be expected to be near 1.0 over the entire interval penetrated.

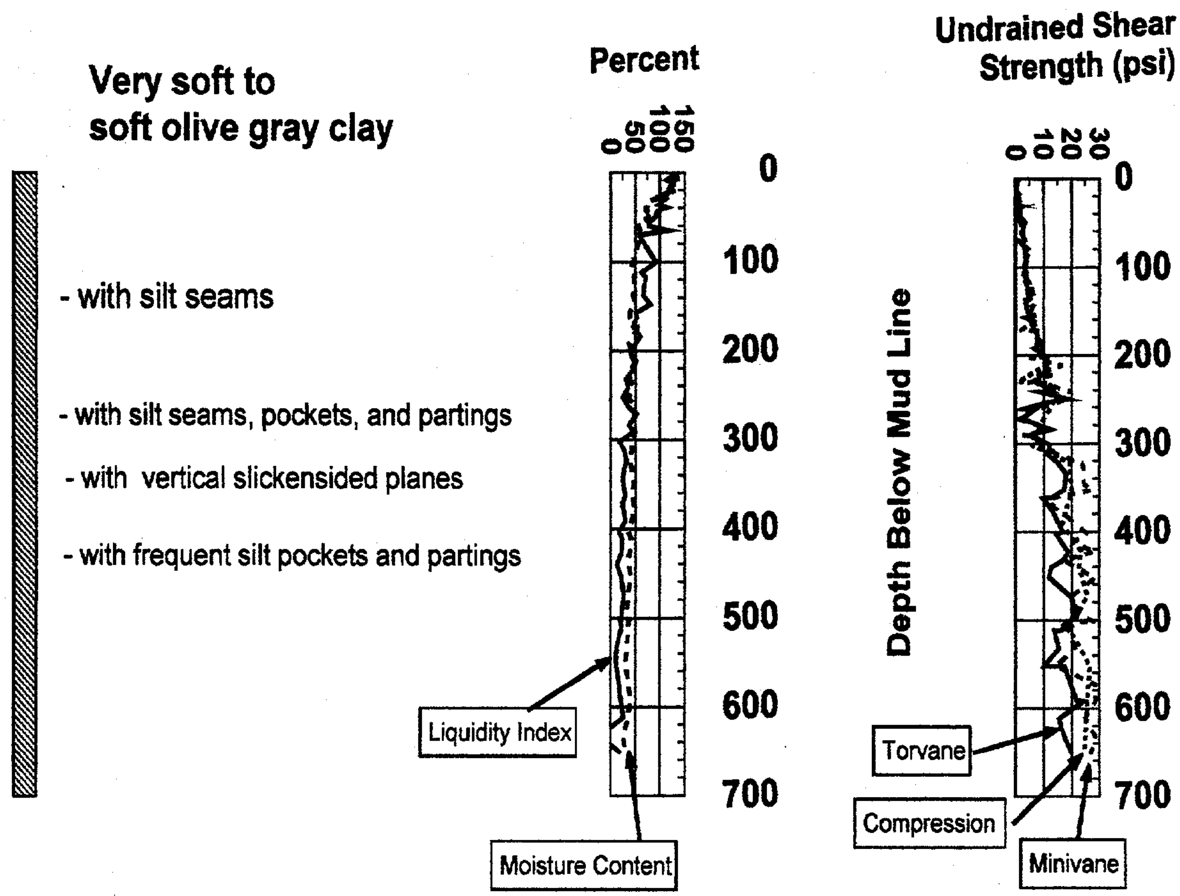


Fig. 8. Lithology, Liquidity Index, Moisture Content and Shear Strength versus Depth for the Green Canyon Example

Measured shear strengths of the sediments reach a value of about 25 psi near the bottom of the interval penetrated. Thus, a significant tensile strength would not be expected. Skempton's formula can be used as an empirical relation between shear strength and effective vertical stress for normally consolidated sediments. Skempton (1957) proposed the formula:

$$\frac{c_u}{\sigma_z} = 0.11 + 0.0037(LL - PL) \qquad (14)$$

which says that the ratio of shear strength to effective vertical stress is about 11%, with a minor correction for liquid limit and plastic limit. At the bottom of the penetrated interval, the effective vertical stress is 210 psi, the liquid limit is 61 and the plastic limit is 22. Use of these values in Skempton's formula gives a value of 11.14% and predicts a shear strength of about 30 psi. Thus Skempton's formula appears to be in reasonable agreement with the field data collected in the Green Canyon Area. This formula can be used to estimate the shear strength of shallow sediments for normally consolidated sediments.

Shown in Figure 9 is a plot of the horizontal-to-vertical effective stress ratio, F_σ, as determined from the in situ hydraulic fracture tool run when the soil borings were being taken. Note that all of these results show values near

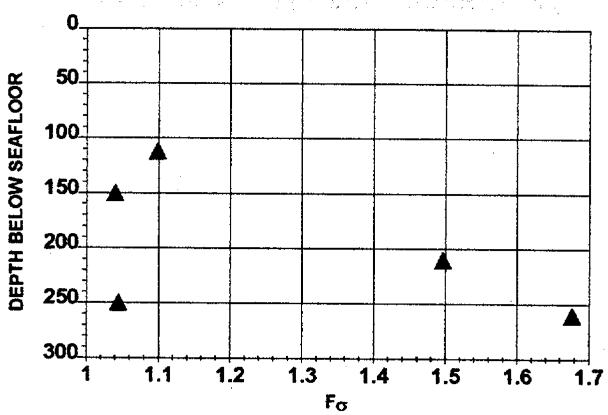


Fig. 9. Ratio of Horizontal-to-Vertical Effective Stress Measured using the In-Situ Hydraulic Fracture Tool

one or in excess of one. Since the tool sees such a small sample of sediment (only a few inches), it is much less likely to encounter major flaws in the exposed sediment. Recall that the effect of stress concentrations in the borehole wall would allow F_σ to be as high as 2.0. The lower limit of F_σ (about 1.0) would be a more representative value to use when a large interval of borehole is exposed.

Since F_σ appears to be near 1.0, a reasonable estimate of formation break-down pressure for clay sediments for this example is the calculated overburden pressure shown in Figure 7. The leak-off test results (Figure 4) tend to confirm that F_σ remains near 1.0 even for the deeper sediments. If well developed sands are known to be present, a lower value for F_σ should be used for those zones. In the absence of leak-off tests for the sand intervals of interest, the use of a minimum observed value for F_σ from the available leak-off test data should be considered. Note that the minimum value seen in Figure 4 was about 0.8.

5. Conclusions and recommendations

Geotechnical studies using soil borings provide a useful and sometimes overlooked supplement to the available data needed to design a well for shallow-gas well control. In the past there was sometimes only marginal interaction between the geotechnical engineer designing the foundation of an offshore structure and the petroleum engineer designing the casing program of the wells to be drilled from the structure. The assumptions that the shallow sediments are too weak to consider shutting-in the well prior to setting surface casing and that the diverter operations would always solve the problem, regardless of conductor depth selected, are not always correct. Design loads and failure mechanisms for shallow well control operations need to be viewed in a systematic way.

Since the entire structure can be put at risk by sediment failure occurring during well control operations, a strong case can be made for a more interdisciplinary approach to the design of the structural and conductor casing strings. Interpretation of the soil borings data by the geotechnical engineer can provide useful casing design data. Loads imposed during well control operations should be considered in addition to loads imposed by the weight of subsequent casing strings. Rather than stopping a soil boring at a depth where sufficient sediment strength has been penetrated to design a foundation for the structure, boring could continue until sufficient data has been collected to allow the structural and conductor casing strings to be designed with confidence for well control operations.

The described method of determining fracture pressure from soil borings tests gives excellent results for the areas studied in the Green Canyon Area, Gulf of Mexico.

6. Acknowledgments

The authors wish to acknowledge Tom Hamilton, Senior Vice President, and Jane Volk, Librarian, of Fugro-McClelland Marine Geosciences, Inc. for their invaluable assistance in this study.

7. Nomenclature

ϕ = porosity
ϕ_0 = surface porosity
ϕ_{fric} = angle of internal friction

ρ_b = bulk density
ρ_{fluid} = pore fluid density
ρ_{matrix} = matrix or grain density
ρ_{sw} = density of the seawater
σ_{fail} = failure stress
σ_h = horizontal stress
σ_{min} = minimal effective (matrix) stress
σ_n = normal stress
σ_{rw} = principal wellbore stress in the r direction
$\sigma_{\theta w}$ = principal wellbore stress in the θ direction
σ_{zw} = principal wellbore stress in the z direction
σ_{ten} = tensile stress
σ_z = vertical effective (matrix) stress
τ_{fail} = failure strain
a_1, a_2, a_3 = constants (See Eq. (13) and Table 2)
c = cohesion
c_u = undrained shear strength
D = depth
D_w = water depth
D_s = depth of the sediment below the seafloor
F_σ = horizontal-to-vertical matrix stress coefficient
g = gravitational constant
K = the porosity decline constant
LL = liquid limit
PL = plastic limit
p = pore pressure
p_{frac} = fracture pressure
p_{init} = initial fracture pressure
p_w = wellbore pressure
S = overburden pressure
S_{pob} = pseudo-overburden pressure

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DRILL STRING SAFETY VALVE REVIEW

Slide 1 - Picture of typical valve.
Drill String Safety Valves (DSSV's), including kelly valves and full bore stabbing valves, are routinely utilized in drilling operations as part of the well control equipment. Unlike other well control related components, such as BOP's, well heads, casing, etc., DSSV's are governed by a very weak API specification that only specifically addresses kelly valves (API Spec. 7, Section 2). Hence, operators must rely upon the manufacturer's published data to establish verifiable operating limits.

A typical DSSV, as pictured here, has a floating ball that is turned by a single crank through a tongue and groove connection.

Slide 2 - Tabulation of historical problems
The floating ball design is the basic cause of many of the historical problems associated with DSSV's including:

-Lack of a gas tight seal.
-Inability to hold fluid pressure from above and/or outside.
-Lack of pressure integrity at elevated temperature conditions.
-Inability to close on flow due to excessive torque.
-Inability to open with equalized pressure due to excessive torque.

Sound engineering data is required in the selection and determination of suitability for service on all unregulated oil field equipment, particularly well control commodities. While historically one might be inclined to acknowledge the acceptable overall performance of DSSV's, it is probably because routine operations have only exposed these tools to very moderate operating stress levels.

Mobil began investigating problems associated with DSSV's in 1993 after several incidence were reported of stabbing valves leaking downhole when stripped into wells under pressure. They first approached manufacturers to determine if they could supply adequate engineering data to verify the suitability of their products for service conditions beyond the kelly valve requirements of API Spec. 7. The results confirmed the need for improved specifications, particularly for stabbing valves.

Slide 3 - Table of Industry Experience
In 1994 a survey of other operators experiences with DSSV's confirmed that there was a general industry need for an improved valve design to address the limitations of current designs and Mobil invited the manufacturers to submit designs for a new generation DSSV. Mobil also approached API and obtained approval to form a task group to revise the kelly valve specifications in Section 2 of API Spec. 7.

Slide 4 - Eight Valves tested by Amoco
As a result of Mobil's interest in the limitations of current DSSV's Amoco shared the results of some basic performance testing they had done in 1990 after their Goldsby blowout (an incident involving flow up a stuck drillstring that two DSSV's failed to stop).

Slide 5 - Test Conditions and Results
For Test number 1 a flow rate of 2-1/2 bpm of 17.7 ppg mud was chosen as representative of the conditions experienced during the Goldsby incident. A choke bypass was used to created the conditions of 0 psi at 2-1/2 bpm and 5,000 psi at 0 bpm through the test valve. Results showed that as the valves closed the pressure upstream of the valve increased due to throttling. At some point, the pressure was great enough to cause the valve mechanism to lock and prevent further movement; even with two men and a cheater bar extention on the normal operating handle!

For Test number 2 only three valves very tested by pumping through them in a partially closed position for approx. 15 minutes with 17.7 ppg mud at 2-1/2 bpm. All three valves were flow cut and two of the three leaked when subjected to pressure testing.

Amoco drew the following conclusion from the testing:
Current DSSV's have serious shortcomings as flow control devices.

and took the following action:
Made it policy to use shear rams on all rigs where kicks likely (as a fall back to contain flow incase DSSV's failed during a kick).

Slide 6 - New Generation DSSV
Only ITAG, a German manufacturer, has proposed an improved DSSV design. To some extent this reflects the lack of financial incentive in this historically price driven sector of the service industry. Main improvement in the new ITAG valve is the use of a trunnion bearing mounted ball with floating seats. Ball will not jam while closing on flow or when pressure is equalized across it.

To stimulate the introduction of performance testing for DSSV's a joint industry project (DEA 100) was proposed by Mobil in February 1995 to fund testing of the new ITAG valve.

Slide 7 - Outline Performance Testing Program in DEA 100
The details are still being finalized but the testing will focus on validating:

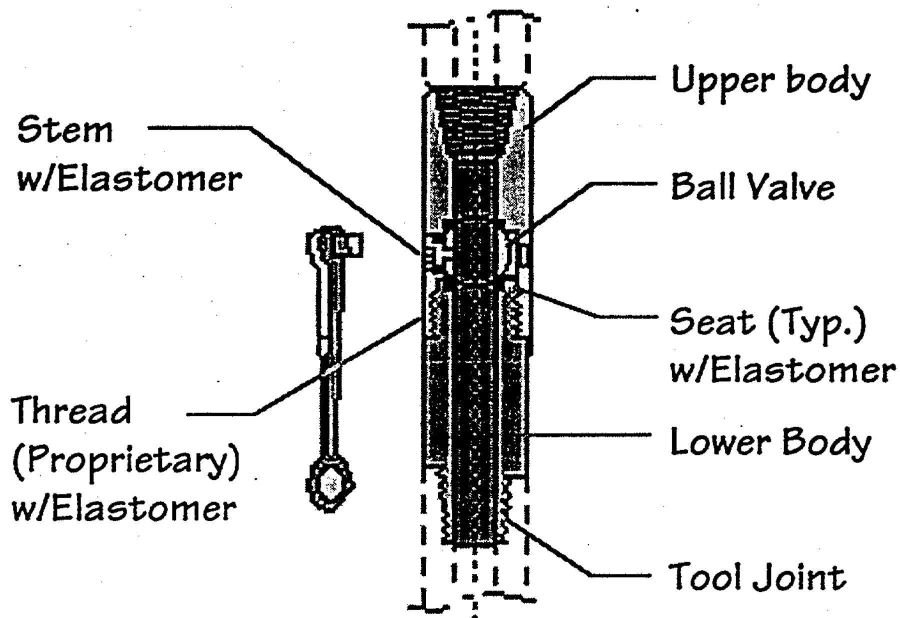
gas tight performance (pressure applied from below, above and outside)
elevated temperature performance
repeated operation in abrasive mud without loss of seal integrity
ability to close on mud flow
ability to open with equalized pressure

Slide 8 - Timing and Funding of DEA 100
Mobil is currently still looking for participants to assist in funding the proposed project to build and test one of the new generation ITAG valves. BP and the Gas Research Institute are still seriously considering participation but at least two more participants are required. Mobil is still hopeful of kicking off the project by mid June 1995.

Slide 9 - New Classification System Proposed
In April of 1995, under the chairmanship of Mobil, the API task group began its work and began thinking about introducing a classification system that would identify valves by their performance capabilities. The task group quickly realized that the way DSSV's are used with top drives also needs to be addressed. Typically the upper valve in a top drive is used as a mud saver valve and the lower valve is used as a manual safety valve.

DRILL STRING SAFETY VALVE REVIEW

TYPICAL DRILLSTRING SAFETY VALVE (DSSV)



DRILL STRING SAFETY VALVE REVIEW

HISTORICAL PROBLEMS AND LIMITATIONS OF DSSV'S

- Lack of a gas tight seal.
- Inability to hold fluid pressure from above and/or outside.
- Lack of pressure integrity at elevated temperature conditions.
- Inability to close on flow due to excessive torque.
- Inability to open with equalized pressure due to excessive torque.

DRILL STRING SAFETY VALVE REVIEW

1994 MOBIL AND INDUSTRY SURVEY RESULTS

Frequency of specific failure types indicated by the number of X's:

Problem:	Mobil	Other Operators
Failure to seal (press. from below)	XXXX	XXXX
Failure to seal (press. from above)	XX	XX
Failure to seal (press. from outside)	XX	X
Failure to close due to high torque	X	XX
Failure to open due to high torque	XXX	XX
Failure to close due to flow	X	X
Failure to seal due to flow erosion	XX	XX

Other problems (list):
Two piece design DSSV's have failed in the proprietary thread due to cracks and caused binding of the ball due to over-torquing.

DRILL STRING SAFETY VALVE REVIEW

EIGHT SAFETY VALVES TESTED BY AMOCO IN 1990:

Manufacturer/Type	Size	Working Pressure psi	Provided by
OMSCO	4-1/2" XH	10,000	OMSCO
Kellyguard	4-1/2" XH	10,000	Petco
TIW	4-1/2" IF	10,000	TIW
TIW	4-1/2" IF	5,000	Oil Field Rental
Hydril	4-1/2" IF	10,000	Oil Field Rental
Kellycock	4-1/2" IF	10,000	Patterson
S-15	n/a	15,000	Halliburton
Scout Master	n/a	15,000	Halliburton

(Information supplied courtesy of Mike Weiss, AMOCO.)

DRILL STRING SAFETY VALVE REVIEW

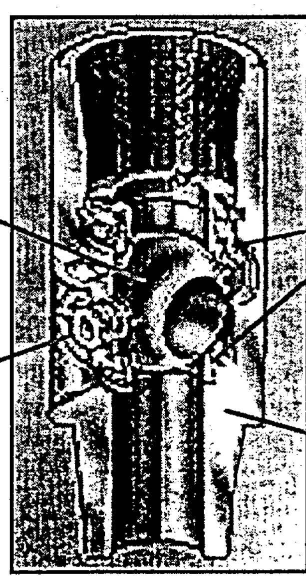
AMOCO TEST CONDITIONS AND RESULTS

- Test 1
  - Pump 17.7 ppg water based mud through the valves at 2-1/2 BPM.
  - Maintained 0 psi at 2-1/2 BPM and 5,000 psi at 0 BPM.
- Results Test 1
  - To close against flow, all valves had to be closed quickly.
  - Failure to quickly close a valve resulted in it being hydraulically locked in a partially closed position.

- Test 2
  - Pump 17.7 ppg water based mud through partially closed valves.
  - Pumped for approx. 15 minutes.
  - Pressure tested (500 and 5,000 psi) following the flow period.
- Results Test 2
  - Only one of the three valves tested passed the pressure testing.

DRILL STRING SAFETY VALVE REVIEW

NEW GENERATION DRILL STRING SAFETY VALVE



Manufactured by ITAG, Celle, Germany

DRILL STRING SAFETY VALVE REVIEW

PROPOSED PERFORMANCE TESTING IN DEA 100 JOINT INDUSTRY PROJECT

- Gas tight performance
  - (pressure applied from below, above and outside)
- Elevated temperature performance
- Repeated operation in abrasive mud
  - (without loss of seal integrity)
- Ability to close on mud flow
- Ability to open with equalized pressure

DRILL STRING SAFETY VALVE REVIEW

DEA 100 DSSV TESTING PROJECT OUTLINE

- Duration of Project and Cost

	Months from start of project 1 2 3 4 5	Cost
Build Valve		50 $M
Test Valve		75 $M
	Total Project Cost	125 $M

- Deliverables
  - Performance based testing program for DSSV's (model for API Spec.).
  - A comprehensive testing report for participants.
  - A viable Class 3 DSSV for the industry.
- Cost of Participation in the Project
  - Five participants @ $25,000 each. (Mobil + four others.)

Contact for further information
Brian Tarr, Mobil E & P Technical Center. Tel. (214) 951-2945 FAX (214) 951-2512

DRILL STRING SAFETY VALVE REVIEW

NEW DSSV CLASSIFICATION SYSTEM PROPOSED

DSSV CLASS	FUNCTIONALITY	AVAILABILITY
1	Only holds pressure from below. May be H2S rated. No temperature rating. Difficult to close on flow. Cannot open with high ΔP.	TIW and like. SMF (Also holds press. above.)
2	As Class 1 but also: Holds pressure from above and outside.	Hydril ITAG
3	As Class 2 but with performance qualifications for: Operating temperature range. Flow shut off. Operation at full rated ΔP. Gas tight sealing.	ITAG prototype

Analysis of Platform Vulnerability to Cratering Induced by a Shallow Gas Flow

Principal Investigator: Adam T. Bourgoyne, Jr.
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Baton Rouge, Louisiana 70803-6417

ABSTRACT

A flow from an unexpected shallow gas sand is one of the most difficult well control problems faced by oil and gas well operators during drilling operations. Current well control practice for bottom-supported marine rigs usually calls for shutting in the well when a kick is detected if sufficient casing has been set to keep any flow underground. Even if high shut-in pressures are seen, an underground blowout is preferred over a surface blowout. However, when shallow gas is encountered, casing may not be set deep enough to keep the underground flow outside the casing from breaking through to disturb sediments near the platform foundations. Once the flow reaches the surface, craters are sometimes formed which can lead to loss of the rig and associated marine structures.

The sediment failure mechanisms that lead to cratering have been poorly understood. In addition, their has been considerable uncertainty as to the best choices of well design parameters and well control contingency plans that will minimize the risks associated with a shallow gas flow. The objectives of this study were (1) to identify and describe various possible sediment failure mechanisms that can lead to cratering, (2) develop improved correlations for estimating the break-down resistance of upper-marine sediments, and (3) to evaluate alternative well design procedures and well control contingency plans using the improved correlations. The goal of this research is to increase the safety of drilling operations, to reduce accidental discharges of hydrocarbons and formation brines to the environment, and to better conserve our natural resources.

Modern contingency plans for handling a shallow gas flow call for diverting the flow away from a bottom-supported rig using a diverter system. The diverter system is used to reduce the wellbore pressure so that it does not exceed the formation break-down pressure. However, results of this study indicate that use of diverter systems does not always prevent cratering. Crater formation during diversion can occur when the diverter is too restricted, allowing formation breakdown pressure to be exceeded even though the well is not shut-in. In addition,

cratering can occur at pressures below the hydraulic breakdown pressure when shallow unconsolidated water sands are present. Water production from shallow aquifers can carry large volumes of sand from the permeable zones exposed to the open borehole. This results in a rapid excavation of aquifer sediments near the wellbore. Subsequent collapse of overlying sediments into the excavated region can open a flow path to the surface.

The above concerns led us to re-examine the controlling design parameters for shallow casings in order to determine when shutting-in a shallow kick is technically and economically feasible. A recent paper by Arifun and Sumpeno (1992) with Unocal Indonesia has indicated that wells are being designed and drilled in their East Kalimantan operations with a well plan that calls for shut-in of all kicks from the surface to the total well depth. These new design concepts were reviewed. Recommended criteria for deciding when to divert and when to shut-in are presented.

SEVERITY OF CRATERING PROBLEM

Although cratering while drilling a well is not a frequent occurrence in the oil industry, when a crater does occur the consequences are usually catastrophic. Large rigs and platforms have been lost in craters with no sign of the rig remaining at the surface. The cost of regaining control of the well and replacing lost structures and equipment can reach hundreds of millions of dollars.

Complete statistics about cratered wells or broaching incidents are not available. However, since cratering is often related to shallow blowouts, statistics about shallow blowouts can be used to show the severity of such problems. Relatively recent blowout statistics were given by Hughes (1986), Adams (1991), Tracy (1992), and Danenberger (1993).

Hughes (1986) compiled information on 425 Gulf Coast blowouts events that covered the period between July 13, 1960 and January 1, 1985. The data was broken down by area and included 242 blowouts in Texas, 56 in Louisiana, 121 in Outer Continental Shelf (OCS), 3 in Mississippi and 3 in Alabama. Gas was present in 82% of the Texas blowouts. The two major operations that were underway when the blowout occurred were (1) coming out of hole (27%) and (2) drilling (25%). Seventeen (7.02%) Texan blowout reports noted that the well blew out around the casing. A total of twenty (8.26%) events reported that the underground flow reached the surface either to form a crater around the well, at a nearby surface site, or caused blowouts from nearby waters wells. All the blowouts that reached the surface outside of casing had a drilling depth to casing depth ratios greater than four.

The study of 56 Louisiana blowouts by Hughes (1986) showed that gas was present in 73% of wells that reported the type of blowout fluid. The rig operations reported to be underway at the time of the blowout included (1) workover operations(37%), (2) coming out of hole (21%), (3) circulating (13.2%) and (4) drilling (13.2%). Hughes does not give details about flows around casing or cratering for the Louisiana blowouts.

The statistics of 121 OCS blowouts reported by Hughes (1986) showed that gas was present in 77% of the cases. A description of the operation described when the blowout occurred was available for 46 events. The rig operations reported to be underway included (1) workover operations (28%), coming out of hole (24%), and drilling (20%). A total of 66 wells described the procedure used to control the blowout. The majority (55%) of the blowouts bridged on their own. About 49% of the 70 wells that listed both date of occurrence and date the well was killed were controlled within one day.

Danenberger (1993) performed a study of blowouts that occurred during drilling operations on the Outer Continental Shelf of the United States during the period 1971-1991. Eighty-three blowouts occurred during this period while drilling 21,436 wells for oil and gas. Four additional blowouts occurred while drilling for sulfur. Eleven of the blowouts resulted in casualties with 65 injuries and 25 fatalities. Fifty-eight of the blowouts that occurred while drilling for oil and gas came from shallow gas zones. Exploratory wells accounted for 37.4% of the wells drilled and 56.9% of the shallow-gas blowouts. Conversely, development wells accounted for 62.6% of the wells drilled and 43.1% of the shallow-gas blowouts.

According to Danenberger (1993), A shallow gas blowout in 1980 was the most serious blowout in the OCS, accounting for 6 of the 25 fatalities and 29 of the 65 injuries. However, there have been no casualties due to blowouts reported during the last seven years of the study.

Oil was not associated with the shallow gas blowouts and environmental damage has been minimal. Two blowouts prior to 1971 are known to have caused oil pollution in the portion of the Outer Continental Shelf under U.S. jurisdiction. An estimated 80,000 Bbl of crude oil was released in the Santa Barbara Channel and about 1,700 Bbl of condensate was released in the Gulf of Mexico.

Although no statistics are given for the OCS on the number of times a crater developed that undermined the foundation of the rig, Danenburger (1993) reported that 71.3% of the blowouts stopped flowing on their own when the well bridged naturally. This is thought to be due to collapse of the uncased portion of the borehole. Flow from 57.5 % of the blowouts ceased in less than a day and flow from 83.9 percent ceased in less than a week. A list of shallow gas blowouts compiled by Adams (1991) indicates that 18 bottom supported structures were damaged on the U.S. OCS by shallow gas blowouts during the 1971-91 period of the Danenburger study. Seven of the U.S. structures shown in the Adams study were reported to be a total loss and extensive damage was reported for another three cases. These ten cases of extensive damage to total loss reported by Adams account for 17.2 % of the 58 shallow gas blowouts reported by Danenburger (1993). Thus 10 lost structures out of 21,436 wells drilled is a rough estimate of the risk from significant cratering.

We were not successful in compiling an estimate of economic loss associated with cratering during shallow gas blowouts. However, an operator reported that the cost due to one event outside of the U.S. was approximately 200 million dollars.

MECHANICS OF CRATER FORMATION

A literature review was conducted to obtain insight into mechanisms possibly involved in establishing a flow path to the surface and in the formation of a crater at the surface. This was done by studying and analyzing a number of historical cases reported in the literature, and later establishing and proposing mechanisms for cratering formation. However, the literature review showed that there are few specific petroleum-related articles about underground blowout followed by cratering. With the exception of very old reports (early 19OO's) and the excellent paper written by Walters (1991), most of the petroleum-related literature contains no specific information about cratering mechanisms. Much of the pertinent literature was found outside of petroleum engineering publications. The scarcity of literature led the research group to look for information by contacting a number of organizations such as oil companies and firefighting and blowout specialists. These contacts, the obtained literature, and the personnel of Louisiana State University, Colorado School of Mines, and University of Oklahoma supplied important information that allowed this work to draw important conclusions about possible cratering mechanisms.

The following sequence was chosen to present the information collected from the sources listed above: The discussion will include:

(1) mechanisms for upward fluid migration that allows formation fluid to migrate upward outside the wellbore and reach shallow unconsolidated sediments; and

(2) proposed mechanisms for crater formation.

Mechanisms for Upward Fluid Migration

Closing the well or restricting the fluid flow in the choke lines will cause the pressure in the well to increase. If the pressure in the well becomes too high, a failure could occur. A path could be established which allows the more highly pressured fluid from below to migrate upward. The primary failure mechanisms identified included: (1) casing failure, (2) failure of the cement bond between the casing and the sediments, (3) tensile sediment failure by hydraulic fracturing, (4) shear sediment failure in permeable zones, (5) wedging open of natural fault planes.

Upward Fluid Migration due to Casing Failure

Casing failure at a shallow depth during well control operations has been reported as the primary cause of a number of craters. Since each larger size casing present outside of inner casing is of lesser strength, after the inner casing string fails, the high pressure fluid will generally find a path to the shallow sediments. Very high pressures are sometimes present if the influx is from a deep, abnormally pressured zone. Proper casing design, pressure testing, and periodic casing wear inspections are the primary means used to prevent this type of failure.

Upward Fluid Migration Due to Failure of Cement Bond

Upward fluid migration through cement channels has also been responsible for a number of blowouts. Fluid seeping around the casing can cause erosion of the borehole-casing annulus, which eventually could lead to a crater. Proper design and planning of cement jobs are basic requirements to prevent upward gas migration around the casing. For this reason, a great deal of effort has been exerted by the petroleum industry to reduce the tendency for channels to form in the cemented annulus during cementing operations. However, the mechanisms involved in the channeling process are not fully understood and although a variety of solutions to the problem have been proposed, none have been consistently successful (Lockyear et. al., 1989).

Upward Fluid Migration Through Hydraulic Fracture

Rock strength is a function of its structure, compaction and type. Rock tensile strength varies in both vertical and horizontal directions. The forces tending to hold the rock together are the strength of the rock itself and the in-situ stresses on the rock. High-pressurized fluid, resulting from the well control operation, inside a wellbore generates hydraulic pressure at the wellbore wall or in the pore spaces of the rock. If the pressure increases, the force applied by the fluid pressure in the rock will become equal to the forces tending to hold the rock together. Any additional pressure applied will cause the rock to split or fracture (Martinez et. al., 1990). Thus, from a macroscopic point of view, hydraulic fracturing occurs when the minimum effective stress at the wellbore becomes tensile and equal to the tensile strength of the rock (Fjaer et. al.,1992).

The fracture will extend as long as sufficient pressure is being applied by injection of additional fluids (Haimson et.al., 1967; Martinez et. al., 1990). Fracture propagation is a function of several factors such as: (a) in-situ stresses existing in different layers of rock, (b) relative bed thickness of formations in the vicinity of the fracture, (c) bonding between formations, (d) mechanical rock properties (including elastic modulus and Poisson's ratio), (e) fluid pressure gradients in the fracture, and (f) pore pressure of different zones (Veatch et. al., 1989). Local stress fields and variations in stresses between adjacent formations are often considered the most important factors to control fracture orientation and fracture growth. Evidence from production logs and other evaluation techniques has suggested that hydraulic fractures usually start in a porous and permeable zone and often terminate before propagating far into the adjacent, impermeable (generally shale) layers. Clay-rich materials normally have higher horizontal stresses and often act as confining layers (Harrison et al., 1954; Warpinski and Teufel, 1984). Most formations are susceptible to hydraulic fracturing. Sand, limestone, dolomitic limestone, dolomite, conglomerates, granite washes, hard or brittle shale, anhydrite, chert, and various silicates are example of rocks for which fracturing operations have been reported as being successful. However, the plastic nature of certain soft shales and clays makes them more difficult to fracture (Martinez et. al., 1990).

Hydraulic fractures will generally propagate perpendicular to the direction of the minimum principal stress (Veatch et. al., 1989; ; Warpinski and Teufel, 1984; Warpinski and Smith, 1989). Thus, the local stress field will generally determine if a fracture will be vertical or horizontal. In most areas, horizontal stress is less than vertical stress, resulting in a vertical fracture.

In terms of well control operations, hydraulic fracturing may lead to the serious risk of allowing upward fluid migration through the fracture. If local conditions indicate that a vertical fracture is likely to occur and not be confined by a layer with a higher horizontal stress, and the permeability of the rock matrix surrounding the fracture is not great enough to dissipate the high pressure, the result can be upward migration of the pressured fluid through the fracture.

Upward Fluid Migration Through Shear Failure

Rock failure caused by shear stress can occur, for instance, when an impermeable formation overlays a permeable formation. In this case, massive shear failure due to the flow of highly pressured formation fluid can occur in the permeable formation before causing fracture of the overlying impermeable strata. The consequences of such massive failure include increase of sand production from the shear-damaged permeable formation, increase of rate of penetration when drilling these strata, and even compaction of these intervals (Walters, 1991).

Upward Fluid Migration Through Fault Planes

Existing fault planes crossing impermeable and sealing layers have been reported as responsible for upward fluid migration which ended in formation of craters (Adams and Thompson, 1989; Adams and Kuhlman,1991; Walters, 1991). Flow through the fault planes will depend on many factors such as normal stress in the fault planes and permeability of the fault-plane-filling sediments. Possible mechanisms of flow through faults include:

(1) the high-pressured fluid wedges open a fault plane at a pressure below that which will cause fracture of the sealing layer; and

(2) increase of permeability due to induced shear dilatancy within the fault plane by the high pressure (Walters, 1991).

Cratering Mechanisms

The cratering mechanisms identified in this study includes (1) borehole erosion, (2) formation liquefaction, (3) piping or tunnel erosion, and (4) caving.

Borehole Erosion.

A number of reported historical cases have indicated that gas seeping around the surface casing is a typical occurrence leading to cratering. Gas or liquid flowing at high velocity around surface casing can cause erosion of shallow formation layers and is one of the mechanisms of cratering. Note also that significant erosion of the borehole wall not only can create a crater but also can lead to a lower pressure in the flowing well, which in turn can be responsible for additional flow of formation fluids (normally water) into the well from all exposed permeable strata. Although erosion of the shallow formation by fluid flow has not been addressed by blowout-related literature, it has been studied in civil engineering problems such as erosion of river bottoms. A number of erosion experiments (Gaylord, 1989; Kamphuis and Hall, 1983) have shown that erosion caused by fluid flow is a function of the fluid velocity and shear stress at the eroding surface. The higher the velocity and shear stress, the higher is the erosion. These studies have concluded that erosion rate, which is defined as mass of eroded material divided by the time interval, is minimal and constant up to a certain value of velocity (critical velocity) or shear stress (critical shear stress). However, erosion rate increases rapidly as velocity increases for velocities above the critical value.

We have made erosion simulations based on erosion models taken from the literature. Our work has shown that as the eroded well bore diameter increases, fluid velocity drops, which caused the rate of erosion to decrease with time. The rate of growth is dependent on the formation erosion resistance and the properties of the flowing fluids. A gas liquid mixture would tend to erode quicker than single phase liquid or gas. However, our work indicated that craters due only to erosion would tend to be small. Shown in Figure 1 are typical results that we obtained.

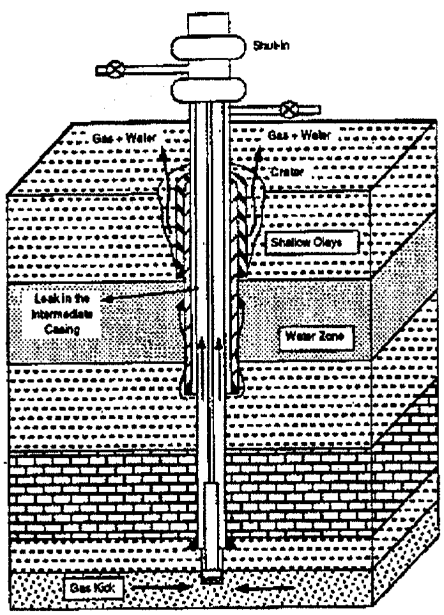


Figure 1 - Schematic of Example Well Configuration used in Borehole Erosion Simulation.

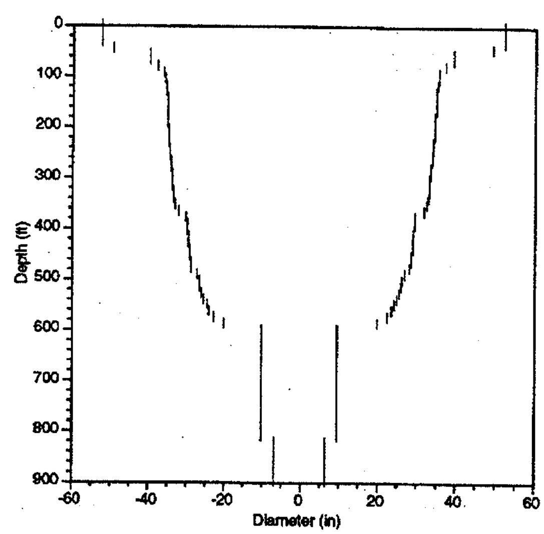


Figure 2 - Calculated Crater Profile due to Borehole Erosion after 5 days

Formation Liquefaction

Liquefaction (or quicksand or boiling) occurs when the vertical effective stresses vanish. Thus, the shear strength of cohesionless soils in the liquefied state is zero (Bell, 1983; Clough et. al., 1989; Lee et. al, 1983; Rocha, 1993; Scott, 1969; Seed et.al. 1981). The weight of the submerged soil is balanced by the upward acting hydraulic pressure gradient caused by the upward flow of fluids through the permeable sediments. This condition is also commonly referred to as a sandboil condition or quicksand condition. The pressure gradient at which liquefaction begins is called the critical pressure gradient (Bell, 1983). This cratering mechanism is thought to be possible only for essentially cohesionless and permeable sediments such as sands.

Liquefied sediments due to seepage forces are often found in excavations made in under-water fine sands subjected to upward fluid flow. As the velocity of the upward seepage force increases further from the critical gradient, the soil begins to boil more and more. If such a condition develops below part of a structure, the foundations of the structure would become unstable with part of it sinking into the liquefied sediments. The presence of a layered sequence composed of individual beds with different permeabilities can be particularly unfavorable if a finer grained cohesionless layer is underlain by more permeable sediments. Formation fluids can then flow through the very permeable layer with little loss of pressure. This results in a steeper pressure gradient in the upper zone.

Piping or Tunnel Erosion

The previous section discussed the potential of liquefaction of cohesionless soils by high-pressure formation fluid. However, if during an underground blowout the formation fluid reaches a cohesive sediment layer, another phenomenon called "piping" or "tunnel erosion" may occur. As the formation fluid flows through the sediments there is a reaction force applied to the matrix material. When formation fluid with sufficient velocity percolates through heterogeneous soil masses, it moves preferentially through the most permeable zones and issues from the ground as springs. Piping refers to the erosive action of some of these springs where sediments are removed by seepage forces. The removal of these sediments form subsurface cavities and tunnels. In order for piping to form, the soil must have some cohesion. Sediments with a larger cohesive strength can support a larger diameter tunnel without collapse (Bell, 1983). Also, for piping to occur in cohesive materials such as clay, it is necessary for a flaw or flow channel to be present to allow a concentrated fluid flow to develop. This could occur because of fracturing (Ghuman et. al., 1977). In the piping process, the formation fluid must be moving with sufficient volume and velocity to transport clay particles. This flow may be in a supersaturated layer with an under-layer of impermeable material, or along cracks or flaws in relatively impermeable sediments (Crouch, 1977). Piping may develop by backward erosion. In such a case, sediment erosion may grow from the exit toward the source of fluid supply (Bell, 1983). Finally, if erosion due to piping reaches a critical value, entire structures (dams, houses or drilling platforms) can collapse due to lack of support.

Caving

In this work, caving is defined as the collapsing of solids within and surrounding the well. This collapsing can be by borehole wall failure due to shear failure as the result of the reduction of the hydrostatic pressure in the wellbore, or by tensile failure due to excessive fluid production rate.

Caving due to shear failure can be understood by analyzing the origin of the stress concentration at the wellbore wall. Underground formations at a given depth are exposed to vertical and horizontal compressive stresses that generally are not fully compensated by the drilling fluid pressure after the well is drilled. Therefore, in the case of elastic formations, the load originally carried by the removed rock is partially transferred to the formations surrounding the borehole, creating a stress concentration around the borehole. Stress concentration generally does not present a problem if the well is drilled through competent rock. However, stress concentration in weak rocks or in some shale sections can lead to failure of the borehole.

Problems related to sand and silt production during a blowout include: (1) wear and erosion of production equipment, such as valves, (Fjaer et. al., 1992; Martinez et. al., 1990) and drilling equipment, such as diverter lines, and blowout preventers and (2) excavation of a permeable layer which can lead to the collapse of the overlying sediments. Caving as a result of sand and silt production during a blowout can vary from a few grams or less per ton of reservoir fluid to very large amounts (Fjaer et. al., 1992). One documented case of a cratered well mentions that the material expelled from the crater formed a deposit approximately 40-in thick at the edge of the crater and covered an area of about 99.7 acres (Hills,1932). In one reported case, an entire platform settled several feet after a shallow gas flow. The removal of large sand volumes due to sand production from permeable zones would explain this type of behavior.

SHALLOW-GAS CONTINGENCY PLAN

Developing a well plan that will minimize the risk of structural damage by an underground blowout involves at least three steps:

(1) Obtaining sufficient geologic description and sediment strength data,

(2) Developing a kick prevention plan, and

(3) Selecting a well control strategy and developing a casing program with written contingency procedures for handling a shallow gas flow if the kick prevention plan fails.

Implementation of the contingency plan requires close coordination with the rig contractor and field personnel. Some of the most important areas of coordination include

(1) Verifying through a systems analysis calculation that the diverter system is consistent with the well control plan,

(2) Integration of clear statements of duties and responsibilities (in regard to shallow-gas contingency procedures) into the rig organizational structure, and

(3) Conducting an appropriate training program to insure that the well control plans and contingency procedures are understood and can be carried out by the field personnel.

This report will address the three steps involved in developing the well plan.

GEOLOGIC DESCRIPTION AND SEDIMENT STRENGTH DATA

A prerequisite of any improved well design procedure for safe handling of shallow gas flows is knowledge concerning the breakdown strength and permeability of the upper marine sediments. Key parameters needed to estimate the breakdown strength are the overburden stress and the ratio of horizontal to vertical stress.

Ratio of Horizontal to Vertical Stress

Before fracture pressure can be predicted, the effective horizontal stress must be estimated. For sediments between the surface casing depth and the total well depth, the most common approach has been to correlate the minimum observed ratio of horizontal-to-vertical effective stress, F_σ, with depth. Leak-off test data and incidents of lost-returns have been used to develop empirical correlations for various geographic areas. The correlations were heavily weighted to represent the weaker sediments found at a given depth so that a conservative estimate of fracture pressure could be predicted for use in well design calculations. Once F_σ is obtained from the empirical correlation, the fracture pressure can be estimated using:

$$p_{frac} = F_\sigma \sigma_z + p = F_\sigma (s - p) + p \ldots (1)$$

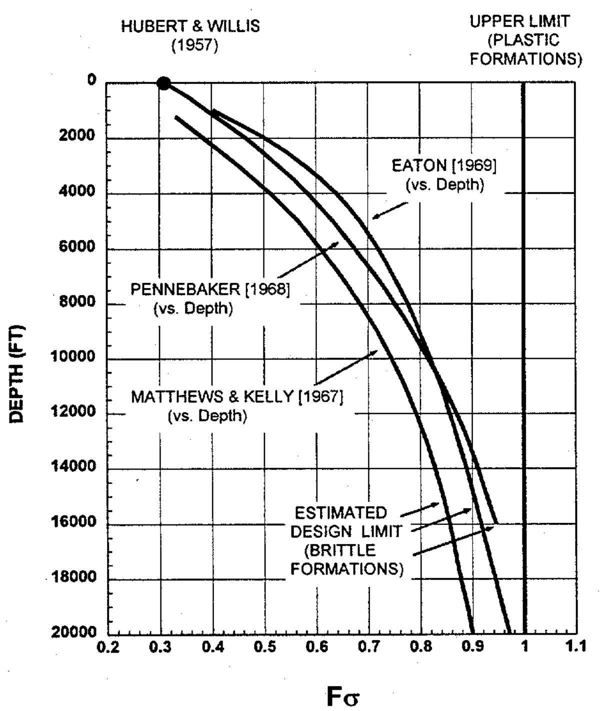


Figure 3 - Ratio of Horizontal to Vertical Stress for the Louisiana Gulf Coast Area

Shown in Figure 3 are several correlations commonly used to estimate the horizontal-to-vertical effective stress ratio for the Louisiana Gulf Coast Area. Note that the ratio decreases for the more shallow sediments and approaches a value of about 0.33 at the surface. Hubert and Willis (1957) determined this value for unconsolidated sands in sand-box experiments conducted in the lab. At deeper depths, the ratio F_σ approaches a value of one as the sediments become more plastic with increasing confining stress.

Extrapolation of the empirical correlations shown in Figure 3 to very shallow depths gives a low value of F_σ, and thus values for shallow fracture pressure are often significantly under predicted. In reality, many shallow marine sediments behave plastically, with F_σ values near one. Use of the correlations shown in Figure 3 for these sediments can result in unrealistic formation breakdown pressures being used in the casing design calculations.

Shown in Figure 4 are F_σ values estimated from leak-off tests from 5 wells drilled in the Green Canyon Area, Offshore, Louisiana. Note that the average observed value of the horizontal-to-vertical effective stress ratio ranges from 0.8 to 1.4 and averages about one. The observed values in excess of one are likely due to: (1) experimental errors which occur while running and interpreting the leak-off tests, (2) the presence of stress concentrations in and around the borehole, and (3) the presence of non-zero tensile strengths in the sediments exposed during the test.

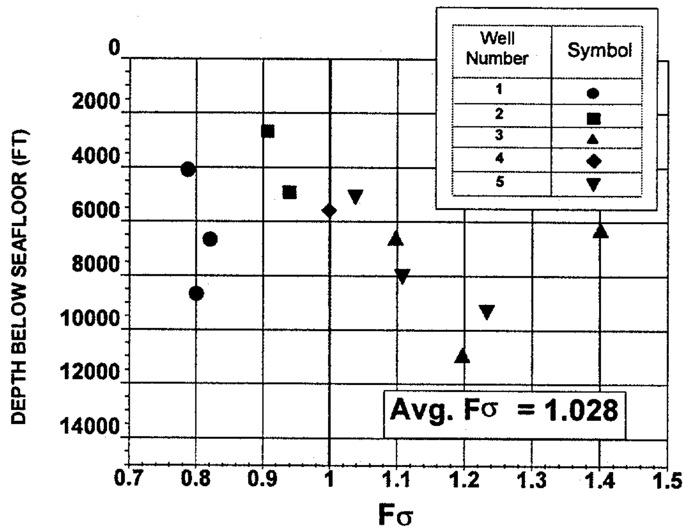


Figure 4 - Ratio of Horizontal to Vertical Effective Stress from Leak-Off Tests in the Green Canyon Area, Offshore Louisiana

Overburden pressure

The overburden pressure is the most important parameter affecting fracture pressure. The overburden pressure, s, at a certain depth can be thought of as the pressure resulting from the total weight of the rock and pore fluids above that depth. Since bulk density, ρ_b, is a measure of the weight of rock and pore fluids, the overburden pressure at a certain depth can be easily calculated by integration of the bulk density vs depth profile.

$$s = \int_0^{D_s} \rho_b g dD_s \qquad (2)$$

Thus, one method for calculating the overburden pressure is to sum up the average interval bulk density times interval height for all intervals above the depth of interest.

For offshore sediments, hydrostatic pressure due to water depth must also be considered and Equation (2) becomes:

$$s = \int_0^{D_w} \rho_{sw} g dD_w + \int_0^{D_s} \rho_b g dD_s \qquad (3)$$

The best source of bulk density data is from in situ measurements made with a gamma-gamma formation density log. Unfortunately such data is seldom available for depths less than the surface casing setting depth. Accuracy of the formation density logs can be poor in large diameter holes, so that a pilot hole may be required to get good measurements in the shallow sediments. Logging-while-drilling (LWD) tools are now available that can measure formation density, but they also require hole diameters no greater than 14 in. Thus a pilot hole may be required to get accurate density measurements in the upper marine sediments. This will often not be cost effective.

Sonic travel times determined from well logs or calculated using seismic data can also be used to estimate the formation bulk density. However, Rocha (1993) found that there was a poor agreement between density values obtained with sonic and density logs in the upper marine sediments. The difficulty stems from uncertainty about the proper choice of matrix travel time values for shallow clay sediments.

Cuttings density data obtained while drilling is sometimes available in the shallow sediments. However, the bulk density of cuttings can be highly altered by the release of confining pressure and by exposure to the drilling fluid.

Overburden stress as a function of porosity

Because of the problems discussed above, detailed information on bulk density is often not available at shallow depths. Thus, density at shallow depths must often be extrapolated from information obtained at deeper depths. This is typically done using porosity instead of bulk density.

Bulk density can be defined in terms of porosity, ϕ, and other variables using the following equation:

$$\rho_b = (1-\phi)\rho_{matrix} + \phi\rho_{fluid} \quad \ldots\ldots\ldots\ldots\ldots\ldots (4)$$

From the above equation bulk density is primarily dependent on porosity since the other variables of grain matrix density and pore-fluid density usually do not have a wide range of values.

Porosity often decreases exponentially with depth, and thus a plot of porosity vs depth on semilog paper often yields a good straight-line trend. This exponential relationship can be described using the following equation.

$$\phi = \phi_0 e^{-KD} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (5)$$

The constants ϕ_0 , the surface porosity, and K, the porosity decline constant, are determined graphically or by the least-square fit method. Substituting Equation (5) into Equation (4) gives:

$$\rho_b = +(1-\phi_0 e^{-kD_s})\rho_{matrix} + \phi_0 e^{-kD_s}\rho_{fluid}$$

which after substituting into Equation (3) and integrating, gives

$$s = \rho_{sw} g D_w + \rho_{matrix} g D_s - \frac{(\rho_{matrix} - \rho_{fluid}) g \phi_0}{K}(1 - e^{-KD_s}) \ldots\ldots\ldots\ldots (6)$$

Area	ρ_{matrix}	ϕ_0	K
Green Canyon	2.65	0.77	323 E-6
Main Pass	2.67	0.59	100 E-6
Ewing Bank	2.65	0.685	115 E-6
Mississippi Canyon	2.65	0.66	166 E-6
Rio de Janeiro Area	2.70	0.67	18 E-6

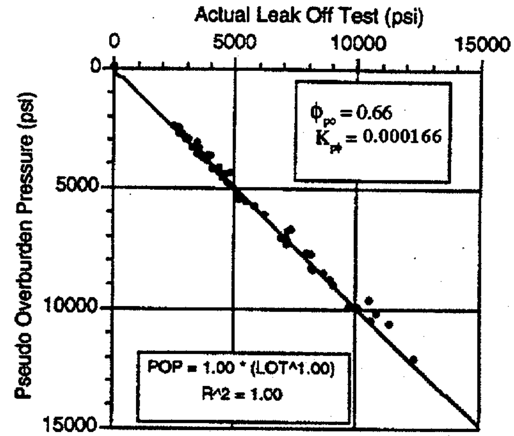
Table 1 - Values for Surface Porosity and Porosity Decline Constant for Several Orrshore Areas

Rocha, (1994) proposed that most shallow marine sediments found in the gulf coast exist in a plastic state of stress and that F_σ approaches one in Equation (1). As the matrix stress coefficient, F_σ, becomes unity, the effect of pore pressure vanishes and fracture pressure becomes equal to the overburden pressure.

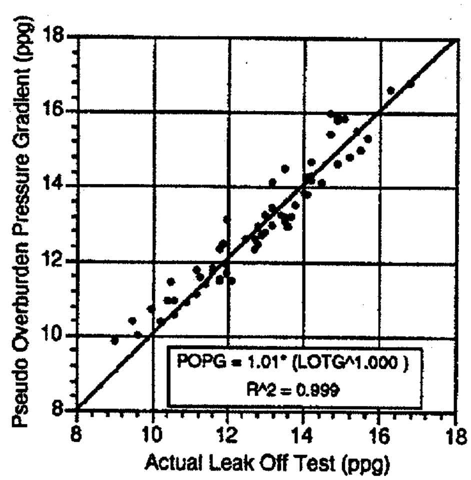
$$p_{frac} = 1.0(s_{pob} - p) + p \quad \ldots\ldots\ldots\ldots (1b)$$

Leak-off tests were then used to calculate a pseudo-overburden pressure, s_{pob}, using Equation (1b). The constants of surface porosity, ϕ_0, and the porosity decline constant, K, are determined by the best fit of the leak-off test data from Equation (6).

We have determined values for ϕ_0 and K for several areas in the Gulf Coast and Brazil. These values are given in Table 1. This approach is best suited for a limited area in which geologic conditions do not vary significantly and for which leak-off test data are available in the upper marine sediments. In sandy areas where F_σ becomes less than one, the correlation will become less accurate and show increased sensitivity to changes in pore pressure.



(a) Comparison of actual leak-off test pressure and pseudo-overburden pressure.



(b) Comparison of actual Leak-off equivalent mud weight to correlation

Figure 5 - Leak-off Test Correlation for Mississippi Canyon Area of Gulf of Mexico

Shown in Figure 5a is the correlation obtained for the Mississippi Canyon Area of the Gulf of Mexico. The correlation was based on 66 leak-off tests. Note the good correlation obtained between actual leak-off pressure and the pseudo overburden pressure based on leak-off test observations. The same results expressed in terms of equivalent mud weight is shown in Figure 5b. Note that the spread in the data is about plus or minus one pound per gallon of equivalent mud density.

Other correlations were attempted which considered effective stress in addition to overburden stress and thus took into account changes in pore pressure. A shallow transition zone to abnormal pressure was seen in these wells. However, no improvements in the correlation index could be achieved with this increased complexity. This may be since F_σ was found to be near one.

Use of Soil Borings Data

Work was also done to determine how soil borings can be used to help fill-in some of the missing data needed in designing the shallow portion of the well. Example data from the Green Canyon area of the Gulf of Mexico will be used to illustrate the recommended approach. Soil boring data are integrated with deeper well log data to provide a more accurate estimate of overburden stress and formation break-down pressure.

A number of tests are routinely run on soil borings by geotechnical engineers to determine the load bearing capacity of the shallow sediments. The physical properties tested generally fall into one of three categories:

1) weight/density measurements,
2) Atterberg limits, and
3) shear strength measurements.

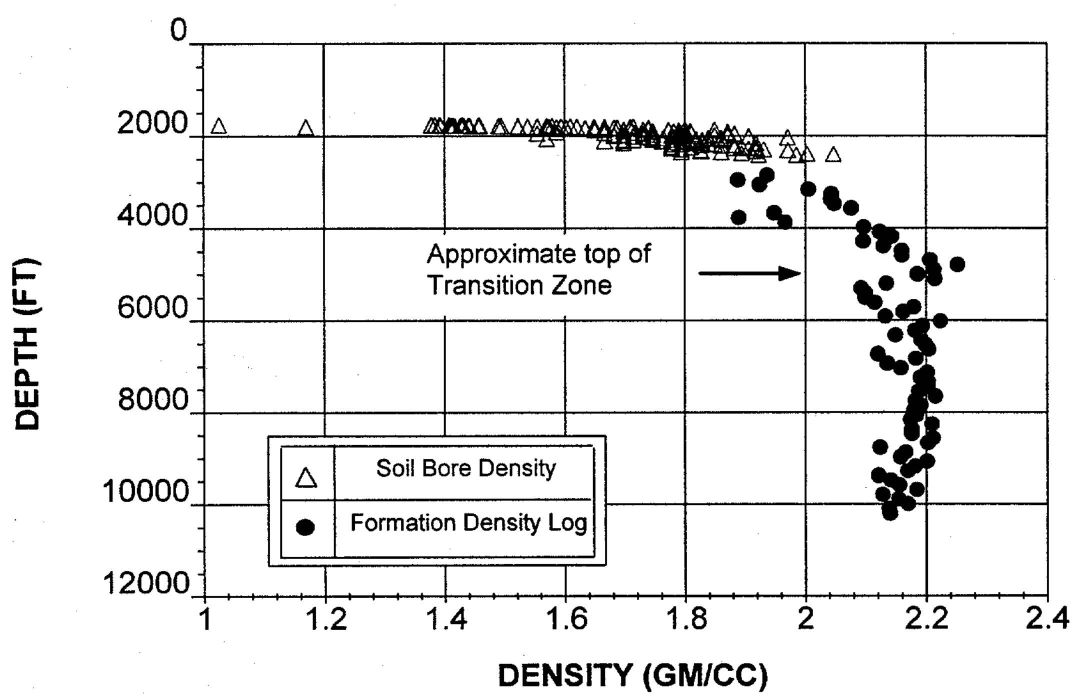


Figure 6 - Sediment bulk density vs. depth
for the Green Canyon Area Example

Weight/density measurements include moisture content, wet unit weights, and dry unit weights. Atterberg limits tests measure plastic limits and liquid limits of the soil. Shear strength measurements are done with miniature vane, Torvane, Remote vane, Cone Penetrometer (CPT), and triaxial shear tests.

After being retrieved on the surface but before being extruded from the sample tube, miniature vane tests for shear strength are performed. The sample is then extruded from the sample tube and cut. Representative portions are carefully packaged, sealed, and sent to labs for further testing. The remainder of the sample is tested in the field. Normal field tests are the Atterberg limits tests, visual mineral and size classifications, and various strength tests. Lab testing includes unconsolidated and undrained tests for shear strength.

The hole from which the sample was taken can also be tested to obtain in situ values of shear strength, hydraulic fracture pressure, temperature, etc. using specialized tools at the bottom of a drill string.

Shown in Figure 6 is a composite density versus depth profile for a well in the Green Canyon area. The lower portion of the profile (circles) was obtained from a formation density log run in a nearby well. The upper portion of the profile (triangles) was obtained from wet unit weight data collected from soil borings. Integration of this profile produced the overburden pressure versus depth curve shown in Figure 7. Also shown in Figure 7 for comparison is the pseudo-overburden curve predicted by Equation(6) when using the surface porosity and porosity decline constant for the Green Canyon Area from Table 1 (from Rocha, 1993).

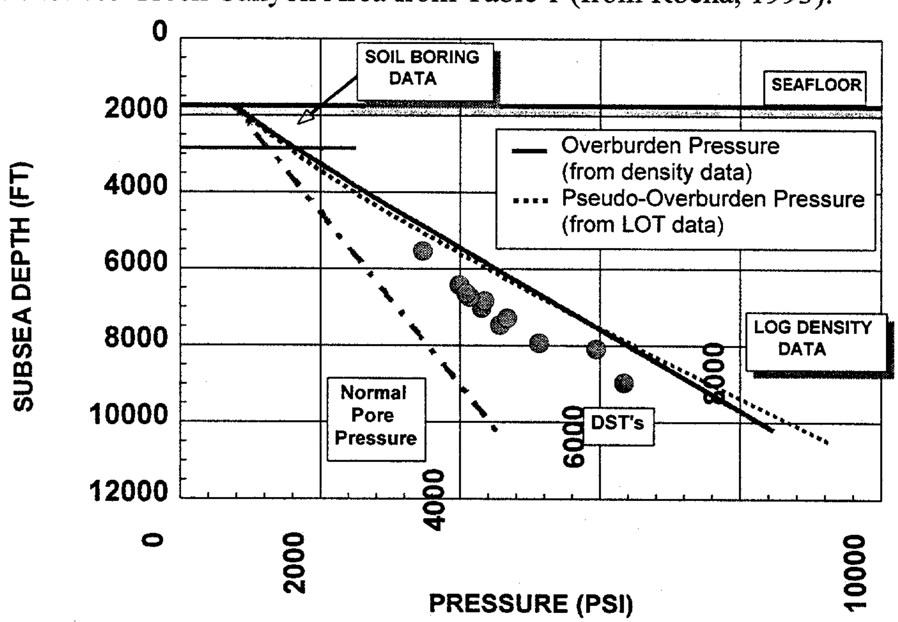


Figure 7 - Overburden Pressure and pore pressure vs depth for Green Canyon Example

Shown in Figure 8 are plots of moisture content, liquidity index, and shear strength versus depth. Also shown is a lithology description. These data show that the sediments penetrated by the soil borings are impermeable (only clay was found) and that the sediments are plastic. The clays are classified as very soft to soft, and the liquidity index dropped below zero only for a small interval near the bottom of the boring. This indicates the ratio of horizontal to vertical effective stress would be expected to be near one over the entire interval penetrated.

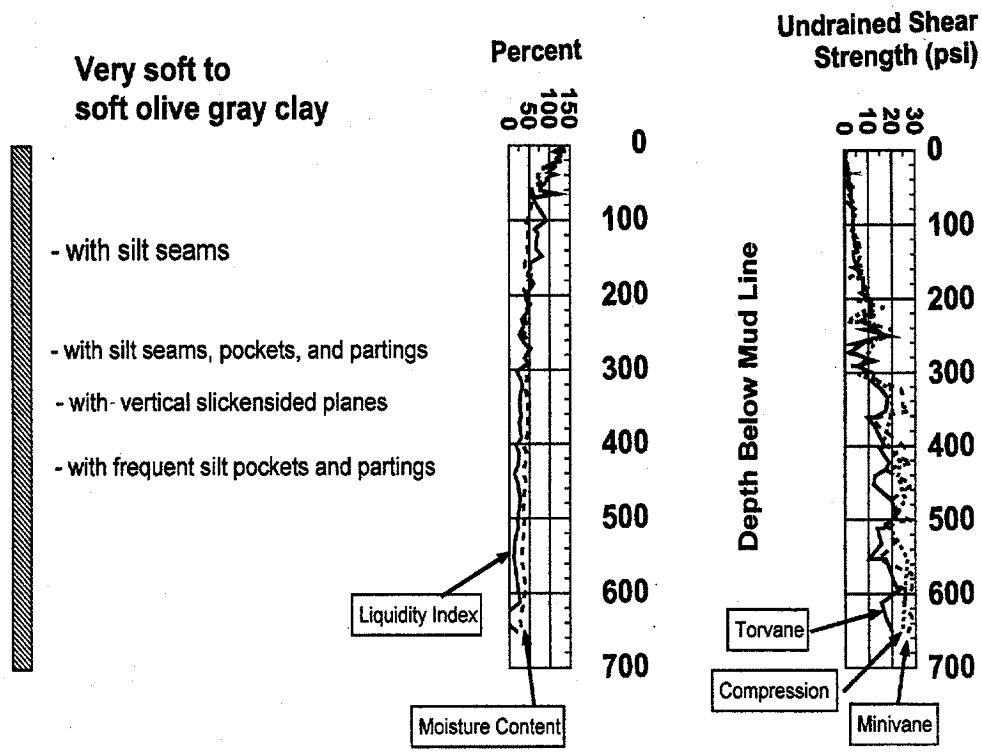


Figure 8 - Lithology, Liquidity Index, Moisture Content, and Shear Strength vs. depth for the Green Canyon Example

Measured shear strengths reach a value of about 25 psi near the bottom of the interval penetrated. Thus, a significant tensile strength would not be expected. Skempton's formula can be used as an empirical relation between shear strength and effective vertical stress for normally consolidated sediments. Skempton (1957) proposed the formula:

$$\frac{c_u}{\sigma_z} = 0.11 + 0.0037(LL - PL) \quad \text{(14)}$$

which says that the ratio of shear strength to effective vertical stress is about 11%, with a minor correction for liquid limit and plastic limit. At the bottom of the penetrated interval, the effective vertical stress is 210 psi, the liquid limit is 61 and the plastic limit is 22. Use of these values in Skempton's formula gives a value of 11.14% and predicts a shear strength of about 30 psi. Thus, Skempton's formula appears to be in reasonable agreement with the field data collected in the Green Canyon Area.

Shown in Figure 9 is a plot of the horizontal-to-vertical effective stress ratio, F_σ, as determined from the in situ hydraulic fracture tool run when the soil borings were being taken. Note that all of these results show values near one or in excess of one. Since the tool sees such a small sample of sediment (only a few inches), it is much less likely to encounter major flaws in the exposed sediment. Recall that the effect of stress concentrations in the borehole wall would allow F_σ to be as high as 2.0. The lower limit of F_σ (about one in this case) obtained using this type of tool would be a more representative value to use when a large interval of borehole is exposed.

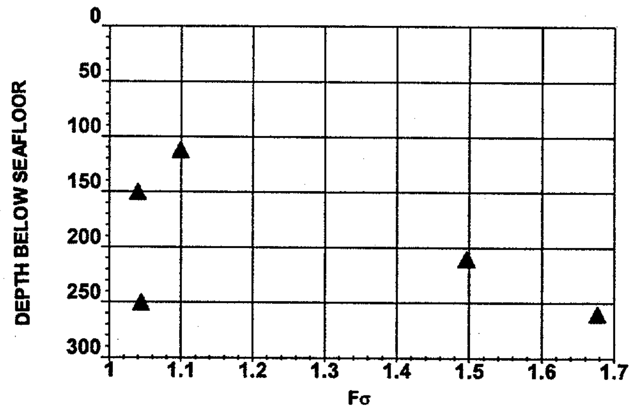


Figure 9 - Ratio of horizontal-to-vertical effective stress measured using insitu hydraulic fracture tool

Since F_σ appears to be near one, the calculated overburden pressure shown in Figure 7 is a reasonable estimate of formation break-down pressure for clay sediments for this example. The leak-off test results (Figure 4) tend to confirm that F_σ remains near 1.0 even for the deeper sediments. If well developed sands are known to be present, a lower value for F_σ should be used for those zones. In the absence of leak-off tests for the sand intervals of interest, the use of a minimum observed value for F_σ from the available leak-off test data should be considered. Note that the minimum value seen in Figure 4 was about 0.8.

KICK-PREVENTION MEASURES

Because of the difficulties in handling gas flows while drilling at shallow depths, considerable attention should be given to preventing such flows when planning the well. Seismic surveys can sometimes be used to identify potential shallow gas zones prior to drilling (Figure 10). If localized gas concentrations are detected by seismic analysis, hazards can be reduced when selecting the surface well location.

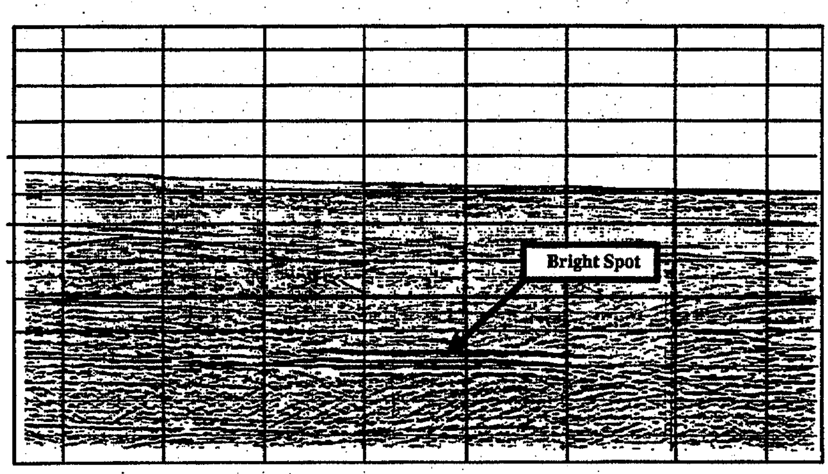


Figure 10 - Example seismic profile showing possible shallow gas accumulation as darker reflection or "bright spot.' (Courtesy of ARCO)

When possible, empirical correlations should be applied to the seismic data to estimate formation pore pressures. This will sometimes permit the detection of shallow, abnormal pressure in the marine sediments. When formation pore pressures can be accurately estimated, an appropriate mud density program can be followed to prevent gas from entering the borehole. One of the most effective ways to prevent shallow gas kicks is through use of an extra pound per gallon of mud density (over the pore pressure) in the shallow portion of the well.

The importance of running a seismic hazard analysis was learned the hardway in the Gulf of Mexico in 1964. The most serious drilling accident in U. S. waters happened while drilling conductor hole in about 150 ft of water at a depth of 461 ft below the mudline. The 30-in. structural casing was set at 121 ft below the mudline. A sudden violent gas flow was experienced which caught fire. Twenty-two lives were lost and twenty-three persons were injured. No shallow hazard surveys were performed prior to drilling and a diverter system was not installed on the rig. This example also illustrates that serious shallow gas hazards can be encountered at very shallow depths.

Drilling practices followed when drilling the shallow portion of the well can also impact the blowout risk. One of the most effective ways to prevent shallow gas kicks is through use of an extra pound per gallon of mud density (over the pore pressure) in the shallow portion of the well. Operations that can reduce downhole pressures, such as pulling the drill string from the well, should be carefully controlled to ensure that a pressure overbalance is always maintained in the open borehole. Pressure changes due to pipe movement tend to increase with decreasing hole size, and thus would be more of a problem when drilling small diameter pilot holes. At shallow depths, a small loss in borehole pressure can result in a significant loss in equivalent mud density. For example, a pressure loss of 50 psi when pulling pipe from a depth of 10,000 ft is equivalent to a loss in drilling fluid density of only 0.1 lb/gal, which can often be neglected. However, the same pressure loss at only 1,000 ft is equivalent to a loss in drilling fluid density of 1 lb/gal, which could be very dangerous. Trip-tank arrangements which keep the well completely full of drilling fluid at all times are better than those that require periodic refilling of the well. Modern top-drive rotary systems permit pumping down the drill-string while pulling pipe and can be used when necessary to eliminate the swabbing effect caused by pipe movement.

Gas-cut drilling fluid can also cause a loss in borehole pressure that can result in a significant reduction in equivalent mud density at shallow depths. For example, severe gas-cut mud observed at the surface can cause as much as a 100 psi reduction in bottom-hole pressure. This pressure loss is equivalent to a loss of only about 0.2 lb/gal at a depth of 10,000 ft which is usually within a normal safety margin. However, this same pressure loss at a depth of 1,000 ft would cause a loss in equivalent mud density of 2.0 lb/gal, which could be very dangerous. Thus, when drilling at very shallow depths, even the small pressure loss due to gas-cut mud can be significant. If gas-cut mud appears prior to setting surface casing, it is advisible to periodically check for flow and to clean the well by circulating. Some shallow gas flow events are thought to have been caused by cutting fault planes through which gas was actively migrating from deeper zones. These fault-cut zones behave as high pressure but low permeability zones which only tend to cause trouble when circulation is stopped for a long period of time.

Conditions favoring a shallow gas flow due to gas-cut mud become more severe with increasing hole size, increasing drilling rate, and increasing length of uncased borehole. Entrained gas, entering the drilling fluid from the sediments removed by the bit at the hole bottom may reduce the hydrostatic pressure below the allowable safety margin opposite a more shallow sand. This potential problem can be controlled by limiting the penetration rate of the bit. An approximate relationship between penetration rate and loss of borehole pressure was previously presented by Bourgoyne, Hise, Holden and Sullins (1978).

CASING PROGRAM

One of the first steps in developing a well control contingency plan is to decide at what point during the drilling operations that it will become safe to close the blowout preventers during a threatened blowout. The most common current field practice for drilling from a bottom supported structure is to use the blowout preventers only after surface casing has been successfully cemented. Prior to that time, the well is put on a diverter if a kick is taken. Given below are examples that illustrate the history that led to this current field practice.

Case 1- This example occurred in the 1960's on a platform set offshore of California in 200 ft of water. Casing had been set with about 200 ft of penetration below the mudline, and the well had been drilled directionally to a measured depth of about 3500 ft. A kick was taken while tripping out of the hole. The drill pipe was dropped in the well and the blind rams closed. The well then blew out around the casing creating an oil boil at the edge of the platform.

Case 2 - This example occurred in the 1970's on a jack-up drilling offshore Louisiana. After setting conductor casing, the well was drilled to the surface casing depth of about 3800 ft. A kick was taken while tripping out of the hole. A diverter was available but was not used. The drill-string was run back to bottom and a conventional well control operation was started. Returns from the well stopped and casing pressure fell to zero. Gas bubbles were initially seen breaking the surface about 70 ft from the rig. Later gas was surfacing on opposite sides of the rig and the rig was abandoned. The gas ignited about 3 hours later. Cratering progressed and the rig was lost. Flames were reported as high as 100 ft above the water.

Case 3 - This example occurred in the 1970's on a platform rig drilling offshore Louisiana in about 300 ft of water. Drive pipe was set with about 170 ft of penetration below the mudline and conductor casing was set with about 430 ft of penetration below the mudline. After loosing 10 bbl of mud while drilling at about 3300 ft, lost circulation material was spotted before tripping out of the hole. The hole was kept filled with mud and seawater while coming out of the hole. The well began flowing on the drillpipe and was shut-in. An attempt was made to circulate the well through the choke, but about 300 bbl of 10 lb/gal mud was pumped with no returns. A boil that was about 50 ft in diameter was observed about 75 yards from the west side of the platform. Additional mud was pumped having density of 12 lb/gal and later of 14 lb/gal. Eventually the platform was abandoned until the well bridged.

The use of diverters has not resulted in a trouble free operation. Diverters were installed on many rigs after the rig was constructed. Multiple bends were required to route the diverter lines to an overboard exit and many of the early systems had poorly designed valves and flexible hoses from the wellhead to the fixed piping. Numerous mechanical problems and severe erosion due to sand production have occurred when the diverter systems had to be employed. Early diverter systems were also undersized and could not handle high flow rates without causing the backpressure on the casing seat to exceed the breakdown pressure. Also, as discussed under cratering mechanisms, work done in this study has indicated that cratering due to caving can occur if shallow aquifers are exposed, even when the casing / diverter system is properly designed and sized.

The operational problems experienced with diverters have resulted in a reduced reliance on diverter systems by some operators, especially in floating drilling operations in which the drilling vessel can be moved off location and is not threatened by cratering. A recent paper by Arifun and Sumpeno (1994) with Unocal Indonesia has indicated that platform wells are being designed and drilled in their East Kalimantan operations with a well plan that calls for shut-in of all kicks from the surface to the total well depth. Other operators have decided to shut-in a kick first, but then switch to diverter operations if the surface pressure exceeds some upper limit, such as 100 psi.

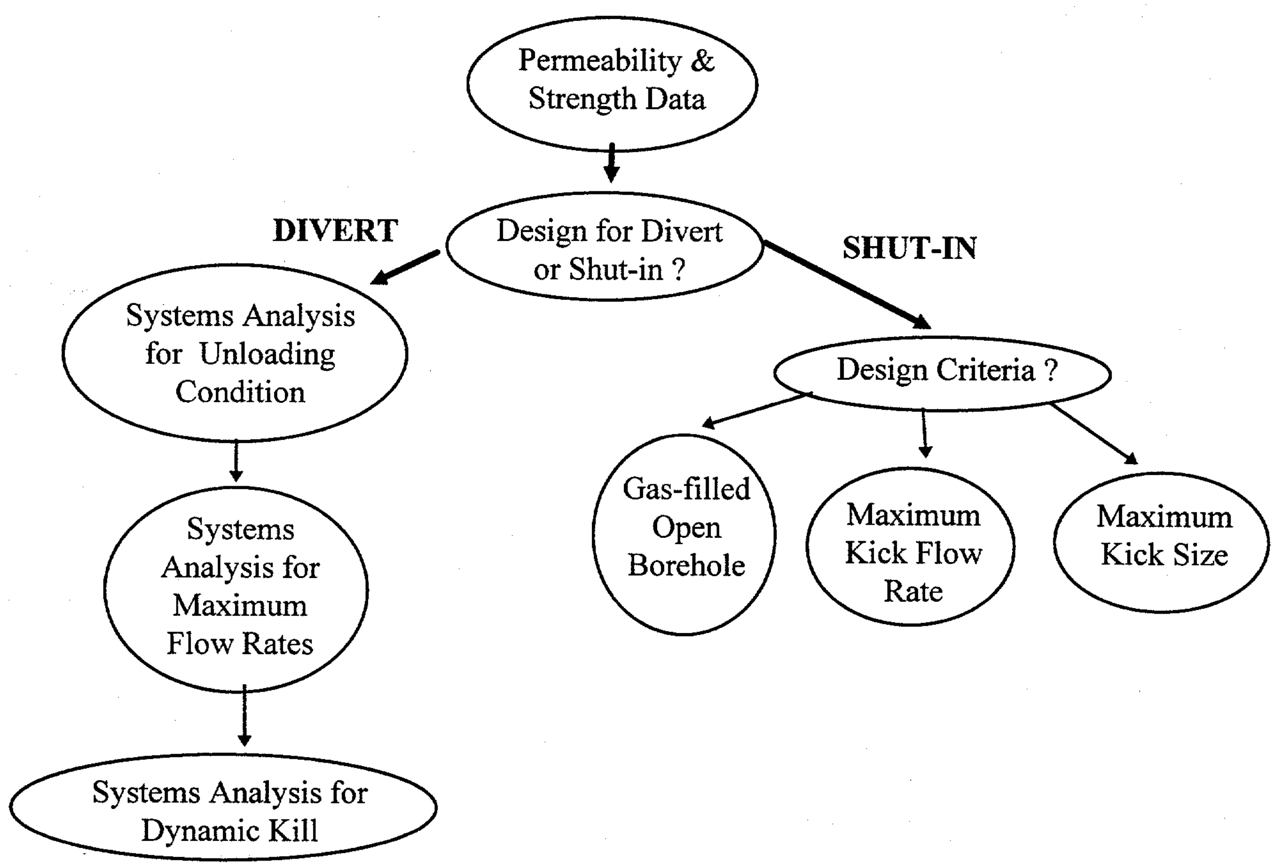
Given below are examples that illustrate the history that appears to be leading us full circle in our approach to this difficult problem:

Case 1 - This example occurred in the 1970's on a jack-up rig drilling offshore Texas in about 200 ft of water. Drive pipe was set at about 190 ft below the mudline and conductor hole was drilled to a depth of about 800 ft below the mudline. After pulling two stands of drillpipe out of the well, it began to flow. Two 6-in. diverter lines were opened and both mud pumps were brought up to speed in an attempt at a dynamic kill. The rig began to list and all personnel were evacuated. When the site was inspected 15 hours later, the rig had collapsed.

Case 2 - This example occurred in the 1980's on a platform rig drilling offshore Texas in about 330 ft of water. Drive pipe having a 20-in. diameter was set about 180 ft below the mud line and the 16-in. conductor pipe was set about 560 ft below the mud line. The well had reached a depth of 2500 ft and drillpipe was being pulled from the hole when the well began to flow. The annular preventer was closed and an attempt was made to open the diverter. However, the diverter valves had been inadvertently locked closed with locking bars. When a diverter valve did open, the flexible hose connecting the wellhead to the diverter line failed and flooded the area with gas, which quickly ignited. Six crew members were killed and 29 were injured. The platform and rig were lost.

Case 3 - This example occurred in the 1980's on a jack-up rig drilling offshore Mississippi in about 100 ft of water. Drive pipe having a 48-in. diameter was set about 150 ft below the mudline and conductor casing having a 10.75-in diameter was set about 1100 ft below the mudline (1300 ft RKB). A formation integrity test was conducted at 1310 ft RKB to 350 psi surface pressure with a 8.9 lb/gal mud in the hole. The well was drilled to the planned surface casing depth of 2900 ft. Upon beginning to trip out of the hole, the well began to flow and was put on a diverter while continuing to pump mud. After pumping 500 bbl of mud, the gas units increased and the rig was evacuated. About 18 hours after the rig was evacuated, the diverter line failed due to sand erosion. About 30 hours after the rig was evacuated, the wellhead was cut-off by sand erosion and the blowout preventers fell. After about four days, the well bridged over. Sand piles were reported all over the rig.

Figure 11 - Decision Tree for Shallow Gas Design



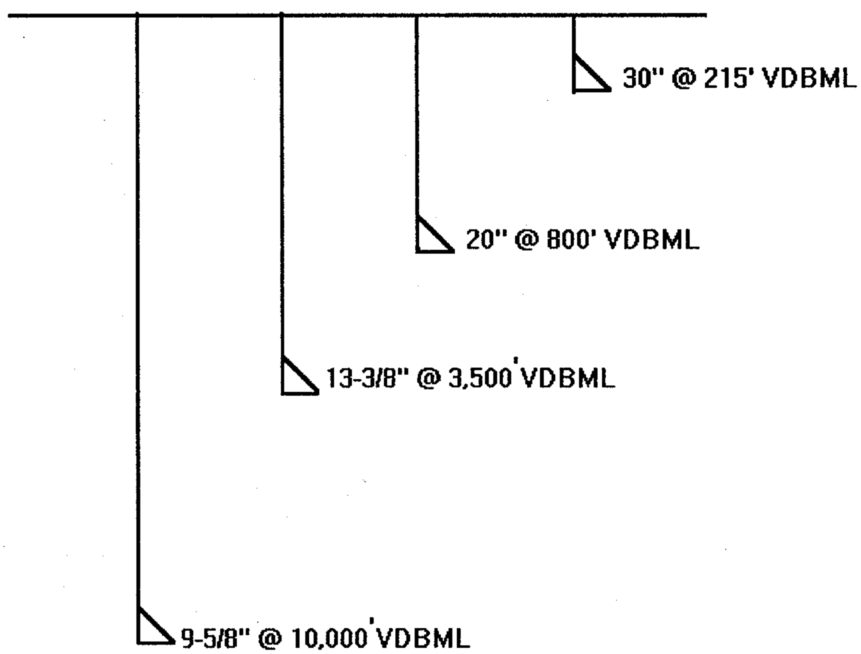
Like most other critical well design issues, the question of whether to design the shallow portion of a well to be shut-in or diverted is primarily a risk management decision in which cost must be balanced against the reduction in risk achieved. Shown in Figure 11 is a decision tree or design procedure which we believe organizes most of the major alternatives that should be evaluated. The items listed in this decision tree were judged to be pertinent based on the crater mechanisms identified in this study. There are several additional branches or decisions that must be made on both the "shut-in" and "divert" side of the tree. As more information is gained in an area, the decision path can be refined.

The thought process outlined in Figure 11 will be illustrated by means of an example. Most of the data included in this example were published by Arifin and Sumpeno (1994) for the Attaka field in Indonesia. The shallow sediments are similar to those found in the Gulf of Mexico, and the formation breakdown strength correlations obtained were very similar to those developed in this study for some Gulf of Mexico areas. Also, the casing programs previously used in this field were typical of those used in the Gulf of Mexico. In order to work some of the examples given, it was necessary to assume some additional information about the lithology.

Casing Program For Diverting Shallow Kicks

A typical casing program that had been previously used for wells drilled with bottom supported rigs in the Attaka field is shown in Figure 12. Structural casing having a 30-in. diameter was driven about 215 ft below the mud line. Conductor casing having a 20-in diameter was set at about 800 ft below the mudline. The next casing string was surface casing which was typically set at a depth of about 3200 ft. The nominal water depth is 200 ft and the nominal air gap is 85 ft.

Figure 12 - Typical Casing Design for Divertering Shallow Gas Kicks



Soil borings data was available to a depth of about 330 ft. The first 100 ft of sediments had an average porosity of about 59% and the porosity observed at the bottom of the soil borings was about 50%. The soil boring showed mostly clay sediments except for a silty sand about 20 ft in thickness at about 165 ft below the mudline. The water content of the clay was above the plastic limit over the entire interval bored. The shear strength at the bottom of the boring was about 15 psi. For potential diverter operations, it would be best to protect the sand at 165 ft with drive pipe to reduce the risk of excavation of this area due to sand production from this potential aquifer. As discussed previously, collapse of overlying sediments into an excavated sandy stratum is one potential mechanism for cratering.

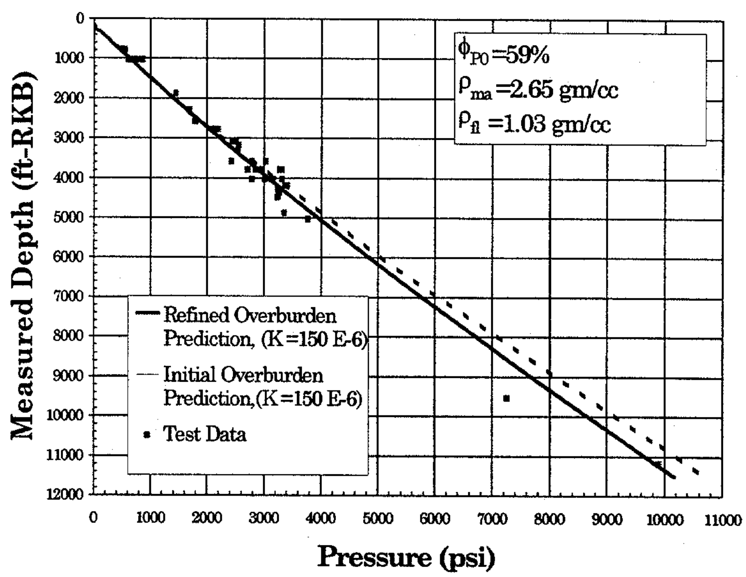
Shown in Table 2 is a spreadsheet calculation using the pseudo-overburden stress calculation based on Equation (6). The calculation assumes that the surface porosity is about 59 %, the interstitial water has a specific gravity of 1.03, and the average matrix grain density is 2.65.

In addition, a nominal porosity decline constant of 150 E-6 ft $^{-1}$ was assumed based on our experience with porosity versus depth trends from other areas of similar sediments. From the available data, the upper sediments appear to be mostly clay, and consequently the ratio of horizontal to vertical effective stress should be near one. Thus, the expected formation breakdown pressure is equal to the overburden pressure plus any tensile strength of the sediments. Plotted as a dashed line in Figure 13 are the formation breakdown pressures computed in Table 2 at various depths. Considerable leak-off test data for the area were published and are also shown in Figure 13. A final adjustment of the porosity decline constant to 100 E-6 ft $^{-1}$ was made based on this leak-off data. The final adjusted formation breakdown pressure curve selected for the casing design is shown as a solid line.

Depth RKB	Depth Sub Surface	Porosity & Bound Water	Pseudo Over-burden Stress + So	Pore Press	Effective Subsea Strength	D2/D1 Ratio
ft	*ft*		*psi*	*psi*	*psi/ft*	
285	0	59.00%	93	88		
400	115	58.33%	178	140	0.78	1.75
500	215	57.75%	252	184	0.76	1.71
1000	715	54.93%	629	408	0.76	1.69
1500	1215	52.25%	1015	631	0.76	1.71
2000	1715	49.70%	1410	854	0.77	1.73
2500	2215	47.28%	1814	1078	0.78	1.74
3000	2715	44.97%	2226	1301	0.79	1.76
2300	2015	48.23%	1651	989	0.78	1.74
2400	2115	47.75%	1733	1033	0.78	1.74
3500	3215	42.78%	2646	1525	0.80	1.78
4000	3715	40.69%	3074	1748	0.80	1.80
5000	4715	36.82%	3950	2195	0.82	1.83
6000	5715	33.32%	4853	2642	0.83	1.87
7000	6715	30.15%	5778	3088	0.85	1.90
8000	7715	27.28%	6725	3535	0.86	1.93
9000	8715	24.68%	7691	3982	0.87	1.95
10000	9715	22.33%	8674	4429	0.88	1.98

Table 2 - Spreadsheet output using Peuedo Overburden Stress Model to predict Fracture Pressure

Figure 13- Comparison of predicted hydraulic breakdown pressure and leak-off tests.



When the well plan calls for diverting shallow kicks, the selected shallow casing design and the available diverter system must be checked using a systems analysis approach described in a previous report. The analysis considers a shallow gas reservoir (at the depth of the next casing seat), the well hydraulic path, and diverter as one system. The maximum pressure observed at the casing seat for several design load conditions are calculated. The design loads are estimated (1) when the well is unloading, (2) when the flow reaches a maximum value, and (3) during possible dynamic kill operations (including the possible use of a relief well). If the well cannot withstand the expected design loads without cratering or if the dynamic kill requirements are not acceptable, the planned casing program/

diverter system is modified, and the systems analysis is repeated. The systems analysis procedure developed in our previous work will not be repeated in this report. However, it has been recently published as Chapter 10, in the book *Studies in Abnormal Pressure* edited by Fertl, Chapman, and Hotz.

Casing Program for Shut-in of Shallow Kicks

Until recently, it has been generally accepted that it was not economically feasible to design a shallow casing string for shut-in on a gas kick. As discussed previously, extrapolation of correlations for the ratio of effective horizontal stress to vertical overburden stress indicated the shallow sediments would have extremely low fracture extension pressures. Leak-off test data on shallow strings was rarely taken for fear of breaking down the casing seat and not being able to regain the integrity of the casing shoe. The ability to obtain an acceptable cement bond in soft sediments has also been questioned. This study has shown that the horizontal to vertical stress ratio is near one in many areas. This, as well as shallow leak-off test data released by Unocal, has indicated that the shallow sediments often have higher hydraulic breakdown pressures than previously believed.

The cost versus risk reduction benefit that can be achieved on an exploratory well by designing the casing for shut-in on shallow gas kicks will be illustrated using the following three design loads:

(1) A large shallow gas kick is taken at a gas influx rate that is high enough to change the multiphase flow pattern in the well to mist-flow and completely displace all of the mud from the uncased portion of the well.

(2) A gas kick is taken at a rate that is insufficient to change the multiphase flow pattern to mist-flow but is large enough to fill the entire uncased portion of the wellbore with the mud/gas mixture.

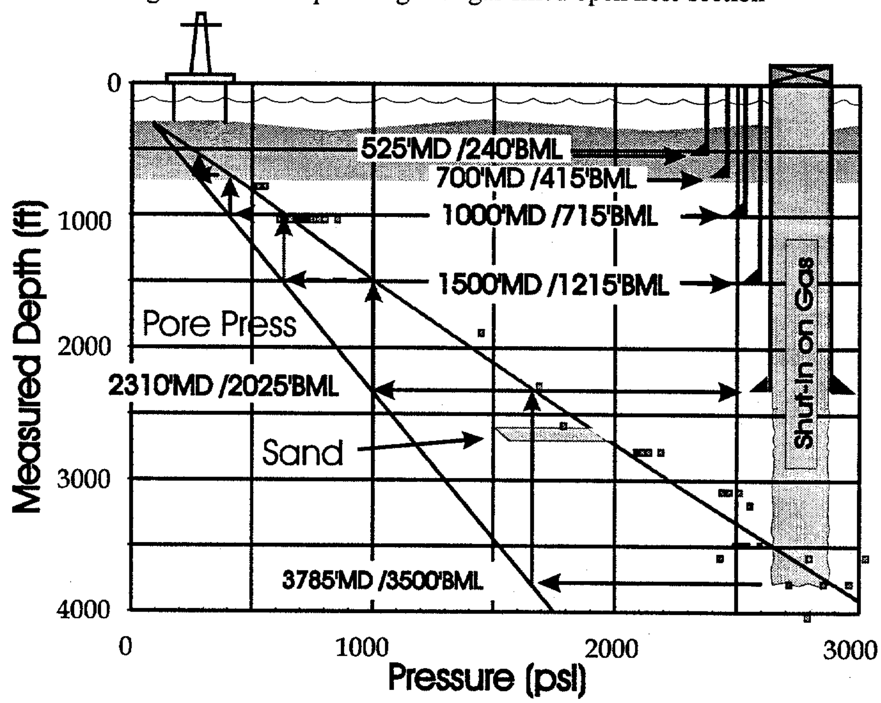
(3) A gas kick is taken, but the well is successfully shut-in before a specified pit-gain is observed.

The first design load is the most conservative and --- at least theoretically --- would be the least susceptible to human error. The third design load is the least conservative, but the consequences of human error could be great.

<u>Design Load based on Gas-Filled Open-hole at Shut-in (Worst Case Analysis)</u>

Consider the conventional casing design of Figure 12, and assume that the surface casing setting depth of 3500 ft below the mudline (BML) is the minimum needed to provide the desired kick tolerance to reach the depth of the next casing string in a conventional casing design procedure. Furthermore, assume that 2500 ft is the amount of sediment penetration for which we feel certain that an underground blowout will remain underground. This is based on the presence of a sand at 2500 ft with a thick, stronger claystone above that would act as a confining layer to a vertical fracture in the sand. It is further assumed that a hazard seismic survey indicated no potential gas zones were present in the upper 800 ft of sediments.

Figure 14 - Example design for gas filled open hole section



Shown in Figure 14 is the casing design required to contain 100% gas in the open borehole. The design process is started at the depth of the surface casing and proceeds in a stairstep manner as indicated by the arrow-heads shown. For the average fracture gradient and normal pore pressure gradient of this example, the D_1/D_2 depth ratio of successive casing strings is about 1.8 (0.8 psi/ft / 0.45 psi/ft = 1.8). To reach a depth of 3500 ft-BML, casing would have to be set at 2025 ft-BML, which is less than the 2500 ft-BML needed to keep a blowout underground. Although breakdown is possible at 2500 ft-BML, formation breakdown pressure would not be exceeded for any kick size at 2025 ft-BML. Casing would have to be set at 1215 ft-BML to reach a depth of 2025 ft-BML, at 715 ft-BML to reach 1215 ft-BML, and at 415-BML ft to reach 715 ft-BML. If the seismic analysis was uncertain, the absence of potential gas zones to a depth of 415 ft-BML could be verified by soil borings or a glory-hole to ensure this depth could be safely reached below drive pipe.

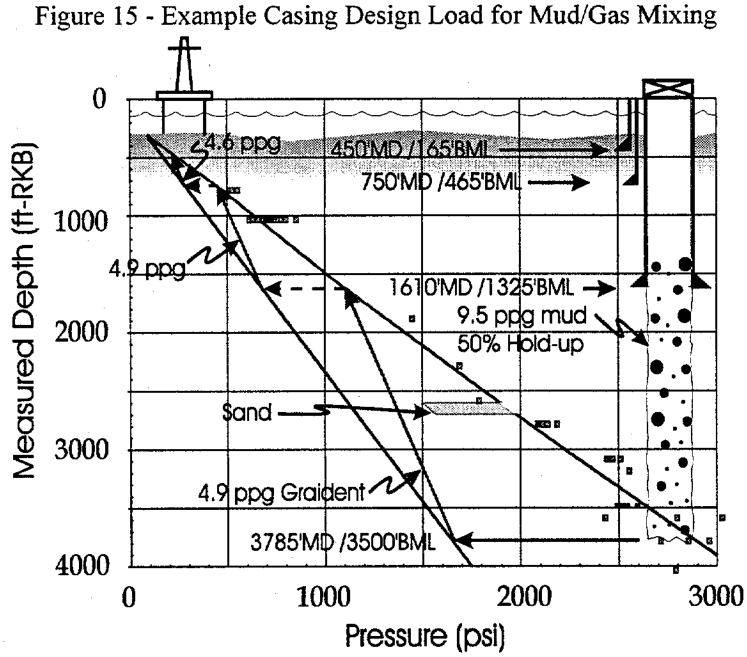
The additional costs associated with this casing design over the conventional design shown in Figure 12 was estimated to be $330,000 The available statistics for the OCS indicate that about one exploration well in 243 drilled have experienced a shallow gas blowout. About 71% of these blowouts bridged naturally due to borehole collapse. Costs of these blowouts have been limited primarily to the loss of the well being drilled. About one exploratory well in 2000 drilled from bottom-supported structures during the past 20 years has had extensive, to total structural damage during the past 20 years. No casualties have been tied directly to cratering in this time period although some resulted from mechanical problems with early diverter designs. Also, pollution has been minimal due to the lack of associated oil. Multiplying the approximate additional cost by 243 yields $80,000,000. Thus if this design procedure eliminated all blowouts due to shallow gas, the value of the well saved would have to be greater than $80,000,000. to justify the additional expense per well. Multiplying the approximate additional cost by 2000 yields $660,000,000. Thus if this design eliminated all cratering events that caused major structural damage or total loss of the structure and associated wells, the value of the structure saved would have to exceed $ 660,000,000 to justify the additional expense per well.

The critical gas velocity for mud droplet removal was estimated in a previous study to be about 600 ft/min (Bourgoyne et.al., 1994). For gas velocities higher than this, all of the mud can be removed from the well. To get a feel for the kick magnitude this corresponds to, consider that in a 17.5-in. hole with 5-in. drill pipe, the annular capacity is 0.27 bbl/ft. Thus, either the pit gain rate would have to exceed 600(0.27)=162 bbl/min, or human error would have to let the well completely unload. For a 9.875-in. pilot hole, the annular capacity is 0.07 bbl/ft and the pit gain rate would have to exceed 42 bbl/min. The presence of a large enough gas zone to cause a flow of this magnitude and yet not be detected by a seismic hazard survey seems highly unlikely. Current practice already calls for setting casing prior to drilling known hydrocarbon bearing formations.

Based on the discussion above, we have concluded that although technically feasible for many cases, the use of this design load will generally be unnecessarily expensive for the potential benefit.

Design load based on Mud/Gas Mixing

Figure 15 - Example Casing Design Load for Mud/Gas Mixing



The maximum rate of gas influx can be estimated from expected maximum formation permeability and thickness for the area. In a previous report, the maximum rate of pit gain for one area was estimated to be about 18 bbl/min in a 17.5-in. hole. For these conditions, the gas would bubble through and mix with the mud, displacing about 50% of the mud from the well. Based on experimental data we gathered in an earlier study (Bourgoyne et. al, 1994), this would result in an effective pressure gradient of 0.254 psi/ft in the mud gas mixture. The casing design for these conditions is shown in Figure 15. Note that the size of the kick does not matter once the top of the multiphase mixture reaches the previous casing seat. The additional costs of this design over the typical design shown in Figure 12 was estimated to be $120,000. Multiplying this cost by 243 yields $29,000,000 and by 2000 yields $240,000,000.

Design Load based on Maximum Pit Gain to Shut-in

The least conservative design load is obtained by assuming that the kick will be shut-in with a maximum total pit gain. The design shown in Figure 16 is based on a maximum tolerated pit gain at shut-in of 200 bbl. The additional costs associated with this design load was estimated to be about the same as the typical design shown in Figure 12.

The major problem with this method is that the potential consequences of human error are greater. If a kick is taken that is larger than the kick tolerance included in the design, there is a possibility that gas could surface under the rig prior to making an orderly rig abandonment. This would be especially true if no diverter was available to release the pressure as soon as gas bubbles appeared.

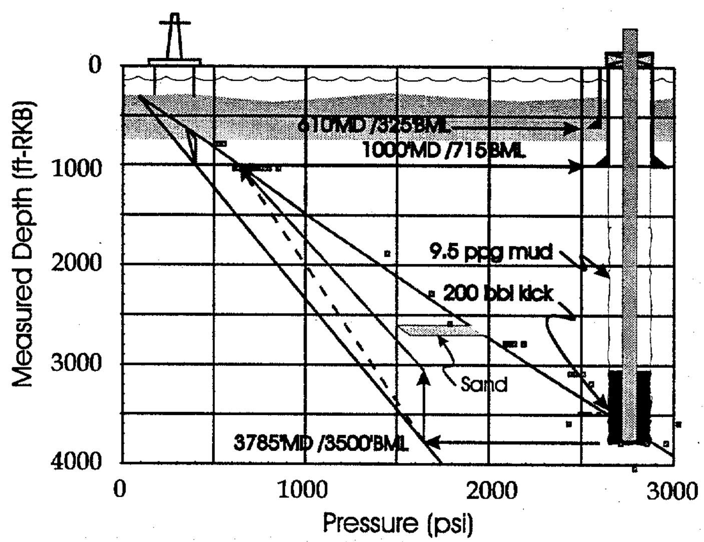


Figure 16- Example Casing Design for 200 bbl Kick Tolerance

SUMMARY AND CONCLUSIONS

This study focused on the vulnerability of a bottom supported marine structure to destruction by the formation of a crater in the sea floor associated with oil and gas drilling operations. Statistics were reviewed that allows the risk of crater formation to be quantified. The mechanisms through which failure of the sediments can occur were identified. Data were collected on the strength of the upper marine sediments in several geographic areas and a new method was presented for developing empirical correlations for hydraulic breakdown pressures of upper marine sediments. Available well design methods for avoiding cratering were reviewed and recommendations for design loads were given.

As a result of the study, the following conclusions were drawn:

1. Statistics gathered by MMS on drilling operations on the U.S. Outer Continental Shelf over the period 1972-92 indicated the following:
   - The primary cause of crater formation due to drilling operations is the unexpected penetration of shallow gas formations.

- One exploratory well out of 243 drilled and one development well out of 536 drilled experienced a shallow gas blowout.
- One exploratory well out of 800 and one development well out of 1917 experienced a shallow gas blowout that did not stop flowing on its own (either due to depletion of the gas zone or bridging of the well due to borehole collapse).
- Approximately one exploratory well out of 2000 and one development well out of 4500 experienced extensive damage or total loss of the structure due to a shallow gas blowout.
- Oil has not been associated with shallow gas blowouts during this period and environmental damage has not been significant.
- Twenty five fatalities and 65 injuries were caused by all types of blowouts during this period. None of these fatalities or injuries were associated with cratering of a bottom supported vessel.
- There have been no casualties due to blowouts on the O.C.S. reported during the past seven years.

2. A multi-disciplinary literature study was conducted to identify the possible mechanism for cratering. The primary mechanisms found included:
    - Cement channels and borehole erosion
    - Formation liquifaction
    - Piping or tunnel erosion
    - Caving due to sand production
3. Cratering can occur even when the well is placed on a diverter and the system is designed so that the hydraulic breakdown pressure of the sediments are not exceeded.
4. Sources of good formation strength data for shallow sediments include:
    - Formation leak-off test data
    - Soil borings
    - Formation density log data
5. Extrapolation of horizontal-to-vertical overburden-stress ratio correlations to shallow sediments often gives a misleadingly low estimate of formation breakdown pressure. The true horizontal-to-vertical overburden-stress ratio is often near one for shallow clay-rich marine sediments.
6. Kick prevention is the best means of preventing structural damage due to cratering.
7. Design options that could allow the well to be shut-in from surface to total depth are technically feasible.

NOMENCLATURE

ϕ = porosity

ϕ_0 = surface porosity

ϕ_{fric} = angle of internal friction

ρ_b = bulk density

ρ_{fluid} = pore fluid density

ρ_{matrix} = matrix or grain density

ρ_{sw} = density of the seawater

σ_{fail} = failure stress

σ_h = horizontal stress

$\sigma_{\min}$ = minimal effective (matrix) stress

σ_n = normal stress

σ_{rw} = principal wellbore stress in the r direction

$\sigma_{\theta w}$ = principal wellbore stress in the θ direction

σ_{zw} = principal wellbore stress in the z direction

σ_{ten} = tensile stress

σ_z = vertical effective (matrix) stress

τ_{fail} = failure strain

a_1, a_2, a_3 = constants (See Eq. (13) and Table 2)

c = cohesion

c_u = undrained shear strength

D = depth

D_w = water depth

D_s = depth of the sediment below the sea floor

F_σ = horizontal-to-vertical matrix stress coefficient

g = gravitational constant

K = the porosity decline constant

LL = liquid limit

PL = plastic limit

p = pore pressure

p_{frac} = fracture pressure

p_{init} = initial fracture pressure

p_w = wellbore pressure

s = overburden pressure

s_{pob} = pseudo-overburden pressure

σ_o - overburden pressure

g - gravity acceleration

D_w - water depth

ρ_w - water density

ρ_{bi} - bulk density in depth interval

$(D_i - D_{i-1})$ - depth interval

n - number of intervals

p - overburden pressure gradient

Δt - interval transit time

Δt_{matrix} - matrix interval transit time

Δt_{fluid} - fluid interval transit time - porosity

a,b - constants

K_φ - porosity declining constant

φ_{p0} - pseudo-surface porosity

$K_{p\varphi}$ - pseudo-porosity declining constant

σ_{frac} - formation fracture

σ_{min} - minimum in-situ stress

σ_p - formation pore pressure

σ_z - vertical stress

F_σ - horizontal to vertical stress ratio

μ- Poisson ratio

$c_1...c_6$,x,A,M - constants used in Zamora's Method

K_T - kick tolerance

SF - kick tolerance safety margin defined by Pilkington

T_m - trip margin

ρ_{mud} - mud density

D_{Shoe} - casing depth

$P_{c\ max}$ - maximum surface pressure

f_k - kick fraction

L_{mix} -mixed zone length

d_{bir} - bit diameter

d_{dc} - drill collar diameter

d_{dp} - drill pipe diameter

V_k - kick volume

ρ_{mix} - density in the mixed zone

V_{mix} - volume of the mixed zone

V_{dc}-hole-drill collar annular volume

EMW - equivalent mud weight

lBML - depth below mud line

Acknowledgments

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17. Reconfiguration of LSU No. 1 Test Well

by O. Allen. Kelly and Adam T. Bourgoyne, Jr., LSU

Objective

The objective of this project was to workover LSU Well No. 1 into a configuration that will accommodate planned research and training. The well was specifically designed for extensive use in the completion of several research topics contained in the recently proposed and approved LSU/MMS research program titled "Development of Improved Procedures for Detecting and Handling Underground Blowouts in a Marine Environment."

Introduction

The LSU Well No. 1 was initially completed in January, 1981, by the Department of Petroleum Engineering to provide a near full scale system for studying well-control procedures that could be applied to deep-water drilling environments. The well was donated to the LSU Department of Petroleum Engineering by Goldking Production Company after an unsuccessful attempt to extend the productive limits of the University Field. The department completed the well using a design that would model a well being drilled at a depth of 6,000 feet from a floating vessel in 3,000 feet of water. The ensuing research utilizing this well resulted in a number of technical papers during the eighties.

In addition to deep water well control related research, the LSU Well No. 1 has been used extensively for basic well control training of personnel such as is required by the MMS prior to working for offshore drilling operations. Also, special deep water well control schools which utilized Well No. 1 have been conducted for Exxon, Tenneco, Arco, Conoco, Zapata, Amoco, and Phillips Petroleum. Basic well control training has been and continues to be made available to LSU students as part of the Petroleum Engineering 4060 Well Control Laboratory. Training wells of this type are especially important for students with limited field experience because they are able to experience realistic well behavior during well control operations while utilizing actual field equipment for controlling the well.

In 1988, the tubing string used to model drill pipe in the LSU Well No. 1 parted above joint 100, just below the triple parallel flow tube. Fortunately, the research program originally planned for this well was already complete, but the tubing failure limited training to utilizing only the upper 3,100 feet of the well. However in 1993, a leak developed in or near the triple parallel flow tube located at 3,000 feet, rendering the well useless for both training and research as long as it remained in that condition.

About the time of the tubing failure, concepts were being developed at LSU for a new five year LSU/MMS research program that would follow the then current five year research program which was drawing to a close. A new well design was being developed to accommodate the emerging research program. As early as April 1993, initial proposals were submitted to the MMS and to LSU's Petroleum Engineering Industry Advisory Board for rework of one of the wells at LSU's research and training well facility. In March and April of 1994, the revised well design was proposed to both the MMS and the industry advisory board. The design submitted was for retrofitting LSU Well No. 1, providing a reconfigured well that would facilitate accomplishing part of the research objectives described in the newly proposed five year LSU/MMS research program and would also accommodate barite settling research being considered by Petrobras. The initial cost estimate projected for the re-work was $150,000 with the objectives for the workover being defined to:

- correct the mechanical problems that developed in the LSU Well No. 1,
- implement a new completion that would support LSU's research plan for the next decade, and
- provide a well facility that can effectively and economically accommodate well control training.

It should also be noted that the new configuration was designed meet the current MMS drilling and well workover training/simulator requirements for MMS well control certification.

Proposed Well Design

The well design proposed in 1994 is shown in Figure 1. The design proposed would utilize the upper 2,800 feet of LSU Well No. 1 with the lower portion being plugged.

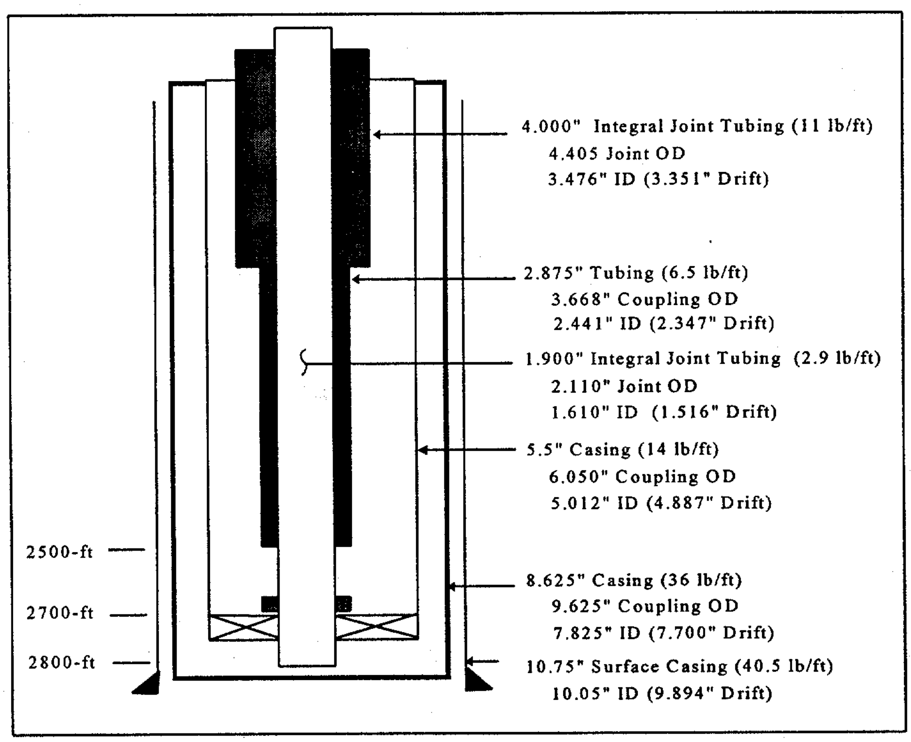

Figure 1 - Initially Proposed Tubular Configuration for LSU Well No. 1

Continual review of the applications associated with this design indicated little interest in the barite settling studies, yet the technical considerations to accomplish this task were numerous, adding significant risk to the design. The decision was made not to install a packer at the base of the 5.5-in casing. The initial idea was that the 1.9-in tubing could be stung into the packer if a leak-proof seal is required at the bottom of the 5.5-in casing or raised (unseated) if circulation is required into the 5.5-in / 8.625-in casing annulus. Dropping the packer concept resulted in the well configuration shown in Figure 2 being designed and implemented.

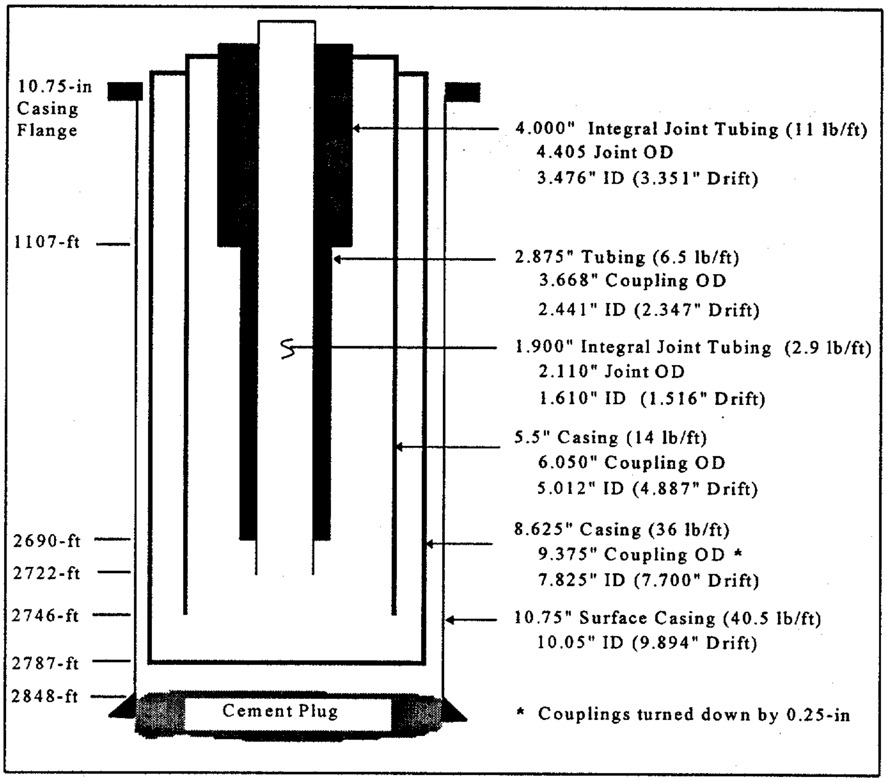

Figure 2 - LSU Well No. 1 Completed Configuration

Recompletion of the well began with a cement plug being set at 2,848 feet, referenced to the 10.75-in casing flange. A pressure test was completed such that both the plug and the 10.75-in casing were tested for a 24-hour period with no pressure loss detected. A 2,787-ft string of 8.625-in, 36-lb/ft, J-55 casing with a bull-plug sealing the lower end was then suspended inside the 10.75-in surface casing. It should be noted that all experiments and training exercises will be contained within this 8.625-in string, which has a burst rating of 4,460 psig. The 10.75-in by 8.625-in. annulus was filled with corrosion inhibited fresh water and will be used only for detecting leaks within the 8.625-in casing. A 2,746-ft string of 5.5-in, 14-lb/ft, K-55 casing was run open ended inside of the 8.625-in casing such that the 8.625-in by 5.5-in annulus can be used to monitor bottom-hole pressure or to simulate a weak (lost circulation) zone in the well during well control training exercises. A tapered string consisting of 1,583-ft of 2.875-in, J-55 tubing and 1,107-ft of 4-in, 11-lb/ft, J-55 integral joint tubing was run concentric within the 5.5-in casing to a depth of 2,690 feet. The final string, a 1.9-in, 2.9-lb/ft, J-55 integral joint tubing was run inside of and extending through the tapered string to a depth of 2,722 feet.

Operationally, the tapered string by 1.9-in tubing annulus is planned for injecting gas kicks during typical well control exercises. However, it can and will be used as an fluid injection string for certain research configurations. The 1.9-in tubing will typically be used to simulate the drill string during well control exercises in addition to serving as wash pipe to clean the well when needed. The tapered string by 5.5-in casing annulus will be typically used for returns to the surface during normal well control exercises and as a injection string for bullheading research and training. The outer annulus, 5.5-in by 8.625-in, will be used to monitor bottom hole pressure as well as provide a flow path to simulate lost returns

The well itself has been completed in full but has not been tied into the choke and pump manifolds. The materials required to complete the tie-in have been donated and began arriving on May 17, 1995. As soon as all the valves, chicksan, swivels, etc., have arrived, the tie-in will be promptly completed.

Contributors to the Workover of LSU Well No. 1

The projected cost for the workover of LSU Well No. 1 will be approximately $180,000, including upgrading the data collection system, modifying the gas vent metering system, and adding another computer controlled choke to control the returns from the 8.625-in by 5.5-in annulus. This effort to complete this project has truly been a joint effort by the MMS, industry and LSU. The following agencies and companies contributed in this effort (listed in alphabetical order):

1. ABB Vetco Gray, Inc.
2. Baroid Drilling Fluids
3. Cooper Cameron
4. EXXON Company, U.S.A.
5. FMC Corporation
6. Halliburton Energy Services
7. Hornback Specialty Company, Inc.
8. Kinley Caliper
9. Minerals Management Service
   U.S. Department of the Interior
10. Mobil Oil Corporation
11. Patterson Rental Tools
12. Patterson Truck Lines
13. LSU Foundation-
    Roy "Phatz" Sullins Memorial Fund
14. Supreme Contractors
15. SWACO
16. Texaco USA

Donations and approvals for donations have been received for the past 18 months in the completion of this project.

Features of the New Design

The new configuration will permit the following training exercises to be conducted (those shown with an asterisk are new capabilities that were not available for the original completion):

- Conventional Circulation of a Gas Kick
- Pump Start-up Procedure for Deepwater Locations
- Conventional Circulation of Gas Kick for Deepwater Locations
- Bull-Heading Operations*
- Conventional Circulation of Gas Kick with Loss Circulation Zone*
- Leak-off Test or Pressure Integrity Test
- Gas Migration in Shut-in Well with Drill String on Bottom
- Volumetric Method of Handling Gas Migration
- Reverse Circulation of Gas Kick during Workover Operations*
- Bull-Heading during Workover Operations*

In addition, the following research projects will be supported by the new configuration:

- Computer Assisted Detection of Underground Blowouts
- Development of Hybrid Well Control Simulator
- Experimental Study of Bull-heading Operations*
- Requirements for Dynamic Kill of Underground Blowouts*
- Experimental Study of Critical Velocity for Mud Unloading by Gas

A lower gas injection pressure of 1440-psig is now possible for generating kicks, which will greatly simplify and reduce LSU's maintenance costs associated with valve repair in the high pressure (5000-psig) gas system. The working pressure of the high pressure system was earlier reduced from 10,000-psig to 5,000-psig because of excessive maintenance costs. However, these costs have remained much higher than expected. In addition, the lower gas injection pressure and smaller casing size will reduce the amount of gas consumed, yet provide valid results for the research projects planned and training exercises to be offered.

Detailed technical specifications and projected operational characteristics of the new design were presented at the LSU/MMS Well Control Workshop held during March 30-31, 1994. Each anticipated type research and training exercise was discussed in detail.

Additional Facility Modifications

Maximizing the utility of the newly configured well required that the facility's data collection system be upgraded and that additional gas measuring devices be installed to get higher resolution gas-out data. Funding for these upgrades has been provided by Petrobras (as part of a research project), the MMS (as part of this year's research budget), LSU, and by equipment donations by SWACO, Drillogic Inc., and Daniels Industries. The newly acquired computer system and data collection system provide the capacity for 32 analog input data channels, 6 analog output data channels, 24 digital input channels and 24 digital output channels. The total cost for this upgrade approximates $14,000 with the majority of the funding coming from LSU and Petrobras. This upgrade increases the data collection capacity of the LSU's electronic system by a factor of four.

The high pressure choke manifold is being modified to accept an additional drilling choke that will be automated for computer control. This choke is the SWACO 10K Kick Killer and was provided to the university by SWACO. This additional choke will permit precise control of the fluid flow out of the 5.5-in by 8.625 annulus when simulating lost returns or underground blowouts. This will be a new feature not presently available at the facility.

As part of the current retrofit, the degassing system has been modified to eliminate gas blow-by through the degasser and into the mud pits, thereby minimizing gas loss when making gas-out measurements. Also, two additional gas metering stations are being installed in the gas vent line to enhance the accuracy of the gas-out measurements over a wider range of gas flow rates. The new design for the degasser system is shown in Figure 3. The degasser system as is now designed will hold up to approximately 15-psig backpressure in the degasser/separator without gas blow-by and do it without the use of a float valve, thereby reducing the risk for failure.

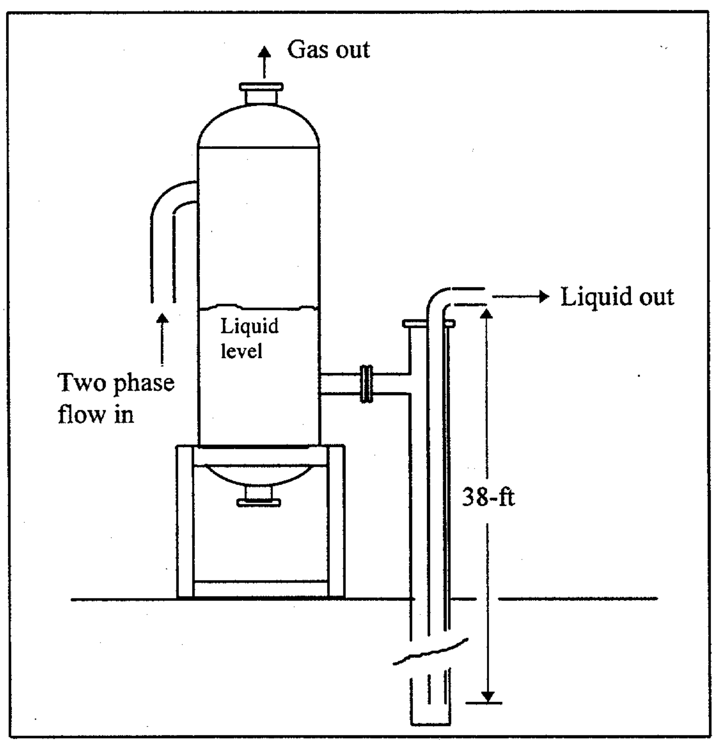

Figure 3 - Modified Degasser System

Modifications are also being made in the gas-out or vent line gas measuring system. The current system only has a 12-in senior orifice meter installed, but the new design will accommodate two additional measuring devices, a 4-in junior orifice meter and either a 2-in turbine meter or a positive-displacement-meter. This system will allow different meters to be reading the gas-out values, optimizing the meter size used with the gas-out rate, such that reading errors will be minimized. Figure 4 depicts how the new design will look upon completion. In the event of pneumatic failure, the 12-in valve is designed to fail-open; but should the valve remain closed for some reason, only a maximum of 15-psig gas pressure would build up before blow-by through the degasser would occur. The three valves shown in Figure 4 will be controlled by the computer so as to optimize gas measurement via quick identification and response.

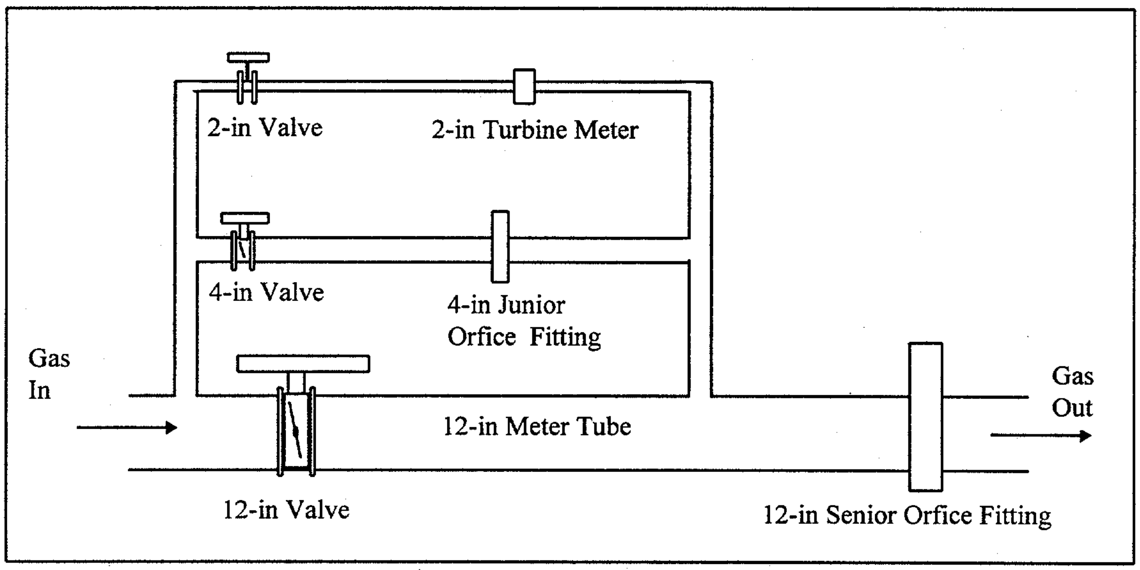

Figure 4 - Gas-Out Meter Tube Modification

Only one other significant change is planned for the near future, the acquisition of a gas compressor which will be used to elevate the 650-psig pipeline gas pressure to as high as 3,500-psig for use in gas kick research and training. LSU funds will be used to purchase this item with the purchase and installation anticipated within four weeks.

Project Status

Recompletion of LSU Well No. 1 as funded by the MMS is complete. No additional work or spending for this project will occur on the 5-year contract extension which ended March 31, 1995.

CONTROL OF ENVIRONMENTAL RISK OF AGING OFFSHORE PIPELINES - Proposal for Survey and Assessment of Available Technology

Andrew K. Wojtanowicz

Department of Petroleum Engineering, Louisiana State University

Paper presented at the LSU/MMS Well Control Workshop

Baton Rouge, Louisiana, May 23-24, 1995

TABLE OF CONTENT

SUMMARY

Presented in this paper is a research project that has been proposed to the LSU/MMS Coastal Marine Institute, in response to the Institute's call for proposals for the 1995 funding cycle. (Typically, the CMI projects are funded as task orders from the Mineral Management Services (MMS), and a MMS Contracting Officer's Technical Representative from the New Orleans Regional Office assigned to each task order.) The Institute, formed by a joint agreement of MMS and the State of Louisiana, has been charged with soliciting proposals in topic areas appropate for the MMS Environmental Studies Program (ESP). MMS has been using this program since 1973 to conduct numerous studies upon many aspects of the Outer Continental Shelf (OCS) and adjacent environments to provide information for management decisions. The scope of these decisions has been recently increased by the Oil Pollution Act (OPA) of 1990, which charged MMS with new responsibilities regarding marine pipelines.

Traditionally, petroleum pipelines have been regulated by several federal and state agencies having different responsibilities and control practices. The recent trend is to consolidate pipeline control, particularly with respect to oil pollution. Under provisions of the Oil Pollution Act (OPA) of 1990, the Minerals Management Service assumed responsibility for all offshore pipelines, including pipelines in state waters.

In February 1994, the Department of the Interior (DOI), The Department of Transportation (DOT), and the Environmental Protection Agency (EPA) agreed on the offshore regulatory duties mandated by OPA 1990. In a memorandum of understanding, Interior's MMS took responsibility for implementing OPA for facilities, including pipelines, located seaward of the coastline. EPA assumed responsibility for non-transportation-related facilities located landward of the coastline, and DOT took over transportation-related facilities, including pipelines, located landward of the coastline. In the result of this memorandum of understanding, MMS assumes responsibility for ensuring pipeline spill prevention and response capability for all marine pipelines, both offshore and near-shore. Therefore, MMS plans to add pipelines in state waters to its current maps of all pipelines on the OCS. Also, the agency is working to develop the best practices for pipeline risk management and control.

The proposed project entails collecting, analyzing, and consolidating information that is dispersed throughout the pipeline industry, professional literature, technical standards, and regulations regarding basic issues in pipeline risk management. These issues are: (1) physical location of pipelines; (2) selection of the best practices and controls from the plethora of existing routines; (3) correlation of pipeline technology with risk; (4) quantification of the risk; and, (5) development of a pipeline risk model to be used as a basis for allocation of resources and formulation of regulatory standards. The project will be performed in close collaboration with MMS and in cognizance of other pending studies, particularly in the area of pipeline mapping.

INTRODUCTION

Marine pipelines carry about one-fourth of the US gas production and one-ninth of the nation's crude oil. Almost all of the nation's pipelines are located in the Gulf of Mexico Outer Continental Shelf (OCS) and offshore state water of Louisiana and Texas. Several dramatic accidents in the late 1980s raised new public concerns about the safety and integrity of marine pipelines. Consequently, the discovery was made that the most widespread risks are due to oil pollution [2].

The term "*pipeline risk*" is defined as the potential for damage resulting from the pipeline failure. *Damage*, in a broad sense, encompasses human injury or death, environmental pollution, or property loss. *Failure* involves loss of pipeline integrity resulting in a spill or gas emission. Both events, damage and failure, have their chances (probabilities) of occurring. Mathematically, pipeline risk is a product of these two probabilities.

The above simple definition of pipeline risk is important for anyone involved in regulating or operating a pipeline system because it shows interaction between *technology* and *location* of pipelines. For example, the amount of damage strongly depends upon where a pipeline is installed. On the other hand, pipeline failure depends upon a variety of technological factors (design parameters, wear, types of operation, testing, and maintenance) as well as physical location of the pipeline. In this project we will provide information regarding both the location and technology of pipelines. We will also try to integrate this information into a single conceptual model of risk control for offshore and near-shore zones of Louisiana.

Those who use technical standards, and those who set requirements for pipelines (operators and regulators) need a conceptual model of pipeline risk because such a model allows determination of *acceptable risk*. While the phrase "acceptable risk" is commonly used, many would be willing to argue that no amount of risk is really acceptable. However, some level of risk is inherent in pipeline operations, and therefore must be tolerated by reasonable regulations. For example, statistically, a 1000-mile long liquid line which is operated under DOT requirements has almost a 100% probability of some kind of accident in a 10-year period.[1] At present, this is deemed to be a *tolerable risk*. The objective of good regulations is to understand and define the tolerable risk now and in the years to come.

The Gulf of Mexico Outer Continental Shelf (OCS) region has always been, and remains by far, the largest oil and gas producer of the four federal OCS regions. The Gulf of Mexico currently accounts for 85 percent of the total acreage under lease in all four of these regions. Federal OCS oil and gas production, which provides about 12 percent of the nation's oil and 24 percent of its gas, can continue to help meet the energy needs of the United States. Since 1954, lease sales in the Gulf of Mexico OCS Region have exceeded 732 million acres. Of this total, the Minerals Management Service (MMS) has leased 53.4 million acres.

Environmental protection of this large area is a responsibility of the federal government. The increased potential for oil spills resulting from the aging pipeline network in the Gulf of Mexico is a major concern. These pipelines transport nearly all OCS oil and gas produced and constitute 99 percent of the total marine pipeline mileage. Efforts are underway to clarify new MMS responsibilities under the Water Pollution Control Act as amended by the Oil Pollution Act of 1990. These responsibilities will include development of the best management and control practices for all pipelines, including pipelines originating in federal waters and continuing into state waters, as well as some state water pipelines.

Recently, the Committee on the Safety of Marine Pipelines, under auspices of the Marine Board and National Research Council reviewed several issues that affect the safety of marine pipelines.[2] The committee found that the pipeline network does not cause excessive damage in terms of human life or injury; pipeline accidents involving deaths or injuries are rare. The most widespread risks are due to oil pollution. The findings of the committee laid the groundwork for the development of risk management measures --- guided by quantitative risk assessment --- which affect pipeline design and operations and safety regulations. The proposed project will be a continuation and further development of several concepts and recommendations reported by the committee.

The committee recommended that MMS develop a pipeline data base covering both state and federal waters. In the proposed project we will collect and analyze data regarding location and operating conditions of pipeline systems that exist both in federal and state waters and the pipelines crossing the shorelines.

The committee suggested that development of a consistent risk management strategy should involve both regulatory agencies and the pipeline operators. In the proposed project we will survey the industry and regulatory profiles and analyze the ways in which regulations and technology affect environmental risk.

The committee also recommended that pipeline safety regulations be based on sound risk and cost-benefit analyses. In the proposed project we will perform risk analysis of available technology for maintaining the integrity of the pipeline network by correlating various monitoring techniques to the environmental fate (impact) of resulting leaks or spills. We will quantify this correlation by considering the cost of these techniques in relation to the benefit of reduced costs of cleanup and remediation. Also, the proposed project will go beyond the committee's suggestion regarding development of a zone-based risk model. We will examine a possibility of combining structural reliability, zone base, and cost-risk models into one model of pipeline risk containing components of technology, location, and economics.

The committee also suggested improvements in leak detection methods to ensure timely detection of a broad range of leaks. The improvements should provide rapid detection of relatively large leaks, daily detection of medium leaks, and periodic (up to two weeks) detection of small leaks. The committee also discovered that accuracy and detectability of pipeline leaks are strongly dependent upon the cost of monitoring equipment, particularly when manual line-balance techniques are replaced by more precise automated systems. Therefore, a cost optimization method is needed. The proposed project will address this issue using SCADA systems characteristics developed by the American Petroleum Institute (API).[3] In addition, part of this project will be a theoretical feasibility study of a new method for leak detection based upon the phenomenon of flow pattern change for multiphase flow in pipes.

PROPOSED PROJECT

The purpose of this project is to compile, analyze, and consolidate existing information on managing environmental risks associated with petroleum pipelines in the offshore and near-shore regions of Louisiana. The project will help to eliminate the current disparities in regulatory strategies, identify the best control technologies, and delineate production pipelines in the offshore and near-shore zones, particularly when the same physical pipeline system exists in both zones. Such pipelines may originate in federal waters (OCS), continue into state waters, and cross the shoreline. They may also co-mingle with coastal pipelines.

In coastal zones, environmental risk considerations and management practices differ from those for offshore and on-shore pipelines. For example, because of its corrosive instability, a coastal zone presents a greater environmental risk of pipeline failure due to external corrosion than offshore because the marine environment is more stable with respect to corrosivity. Also, in coastal zones rapid retreat of the shoreline and lowering of the shore face greatly affect pipeline burial; pipelines crossing the shore may work their way up from their initial depths of cover or eventually become exposed, increasing the risk of being hit by vessels.

From the standpoint of risk assessment methodology, which involves both analysis of exposure and analysis of impact (ecological or safety), this project will address mostly analysis of exposure. The term "exposure" implies spatial density and age of the pipeline network, pipeline regulations, and routine pipeline operation, all in relation to pipeline failure incidents such as leaks or ruptures. The other part of risk assessment, i.e. the ecological effects of pipeline spills offshore, has already been addressed in numerous studies [4, 5] and will be beyond the scope of this project.

Mapping the Pipeline Network

Mapping the pipeline network, particularly at the offshore and near-shore zones where production pipelines from offshore platforms cross the shoreline and intermingle with the on-shore pipelines, will be the initial phase of (and will continue throughout) the project. At present, such maps have been neither completed nor incorporated into a central data base. Also, some mapping work is currently in progress by various organizations. The mapping stage of this project will be expanded beyond merely locating the pipelines because we believe that completing this task alone will not prevent collisions or pipeline damage. Therefore, this project will supplement geographical data with technological information including, but not limited to, ages, sizes, working conditions, and operational routines of the pipelines.

We are planning to focus on offshore and near-shore pipelines crossing the coastal-offshore zone and pipelines coming onshore. We believe that these areas are, first, most sensitive to pipeline risk and, second, controversial with regard to regulatory jurisdiction. Minerals Management Service is now responsible for spill prevention in the state offshore waters in addition to OCS. Offshore state waters, for the purpose of defining the application of the Oil Pollution Act of 1990, begin at an inshore baseline defined as the "coastal line" and extend seaward for three miles. The coastal line demarcation excludes waters behind barrier islands and many inshore waterways. Thus, some marine platforms and pipelines in these areas between state lands and the coastal line do not fall within the application of the act, but they are physically located offshore and are crossing the shoreline. Thus they may pose a significant risk and should be managed similarly to all near-shore pipelines.

In addition to covering presently working pipelines, the mapping stage will also include abandoned pipelines. Oil and gas wells in offshore Louisiana waters are being plugged and abandoned at rates that in recent years have ranged between 600 and 1,400 wells annually.[6] Abandoned well casings and platform legs are required to be cut 15 feet below the seabed and removed within a set time. The production lines associated with these shut-in wells and fields have no future use and are, therefore, abandoned. The transmission lines, however, will most likely continue to serve other fields and, possibly, even newer, deeper water production ventures as well. The extent of abandoned platforms and pipelines correlates directly with the original progression of oil and gas development from coastal marshes to shallow waters to OCS. As a result, most of the lines now being abandoned are in the marshes and shallow state waters of the Gulf of Mexico. Pipelines today are abandoned by removing hydrocarbons, filling the pipe with seawater, and capping and burying the ends to prevent them from snagging nets and anchors. Side-scan sonar, diver inspections, or test trawls with nets may be used to ensure that burial is effective.

In this project, we will collect available data regarding the locations of abandoned pipelines as well as the abandonment methods used by the operators. It has been found that properly abandoned pipelines pose no risk to public safety or to the environment.[2] Thus, the risk of an abandoned pipeline can only be correlated with abandonment practices. Therefore, it is important to know which of the various abandonment practices were used by different operators, particularly in the case of aged pipelines.

In some cases, pipeline systems or segments are not abandoned but are only idled, decommissioned, or mothballed, with the potential for reuse. Maintenance and inspection of pipelines in these cases depends upon the probability of reuse, the cost and difficulty of remediation that may be required, and the potential impact of the in-place and idled facility on both human safety and the environment. In this study we will identify idled pipelines and collect available information on the methods used to maintain these pipelines.

Survey of Industry and Regulatory Profiles

In addition to the mapping phase of our project, we will also perform an industry profile analysis, compiling available information on actual risk management practices used by pipeline operators. Pipeline operating groups routinely perform activities that are driven by initiatives such as compliance with governmental regulation, conformance with industry standard, and continuance of previous operating habits. These three activities vary among operators and together constitute the present profile of the actually practiced technology of pipeline risk management.

Sources of information in this area include state (DNR, OCRM, PS, OGD, DEQ) and federal (MMS, DOT-OPS, USCG, EPA) agencies (see below) that are simultaneously involved in regulating the pipeline industry; technical standards (see below) (ASTM, API, ASME) regarding design, installation, and testing; individual operators' manuals; literature; handbooks; and undocumented information from practicing professionals. In preparing this information for further analysis we will use two basic criteria:

- technical relevance of a parameter or procedure to environmental risk of pipe damage and spillage; and
- relevance of a regulatory requirement to actual mechanisms of environmental risk.

Thus, the main objective of our analysis will not be to compare pipeline regulations and technology but, instead, to relate pipeline regulations and technology indirectly by examining their association with environmental risk.

NOTE:
State agencies include: Louisiana Department of Natural Resources (DNR): OCRM= Office of Coastal Restoration and Management; PS= Office of Conservation - Public Safety; OGD=Office of Conservation - Oil & Gas Division; DEQ = Louisiana Department of Environmental Quality.
Federal agencies include: MMS = Minerals Management Service; DOT - OPS = Department of Transportation - Office of Pipeline Safety; USCG = United States Coastal Guard; EPA = Environmental Protection Agency.
Technical standards include: ASTM= American Society for Testing and Materials; API = American Petroleum Institute; ASME = American Society or Mechanical Engineers.

Analysis of Causal Association

After we complete the industry and regulatory profiles, we will use that information to perform an analysis of causal association between regulatory controls, operational procedures, and environmental risks. In cases where technology and regulatory measures show little or no significance of their causal association, there is no risk control, thus defining the area of concern for regulators and industry. The obvious benefit of such an approach is that it defines only the essential actions necessary to minimize environmental risk from pipelines. However, this analysis also provides a systematic overview of the whole spectrum of measures (both technological and regulatory) which may be involved in environmental risk control.

Risk Analysis of Available Technology

The next stage of the project, risk analysis of available technology, will address technical means for monitoring pipeline integrity that may be applicable to near-shore zones. Several recent reports summarize the technology for maintaining the integrity of pipeline networks.[7-11] However, only a few of these technologies are feasible for these areas. In the analysis, we will consider periodic techniques such as pressure testing, smart pigging, visual surveillance, corrosion control. However, the emphasis will be given to the continuous monitoring and leak detection technology, including manual line balance, SCADA systems, "sniff systems," sonic, temperature, and pressure systems. The analysis will focus on the techniques routinely used by the pipeline industry so that enough data is available on the techniques' performances. We will collect the data and examine a possibility for developing correlations between a control technology and the leak size, particularly for small leaks resulting from non-catastrophic pipe ruptures. Also, we will concentrate on small leaks (rate-wise) because of their high probabilities of occurrence and high potential for pollution.

Our ultimate goal in this analysis will be to relate a control technology to environmental risk using leak size as a correlating parameter. Therefore, we will also need to collect and analyze information regarding the environmental fate of pipeline leaks in the search for a correlation between the leak size and its ecological impact (or remediation cost). The correlation may not be fully quantitative. However, developing a methodology for balancing the cost of leak prevention measures and, thereby, reducing environmental damage will help. As an example, we will try to combine leak detection characteristics of SCADA systems recently developed by the American Petroleum Institute[3,9] with the leak size-fate correlation for offshore Louisiana.

Qualification of Risk Models

Qualification of risk models will be another stage of this project. During this stage we will look at various concepts for modelling the environmental risk of pipelines in search of a model for near-shore zones. An offshore pipeline risk model has been proposed in a recent study of marine pipelines.[2] The proposed model relies heavily upon geographical zoning of an offshore region (Gulf) based upon selected criteria for environmental and human safety risk. The suggested criteria are water depth, pipeline density, and vessel traffic density. A superposition of three maps, each depicting a spatial spread of one magnitude, would identify zones having the higher levels of risk. This zoning approach may help regulators and the industry to set priorities for risk management and identify zones of high risk. The approach does not, however, consider technological factors of pipelines such as age, load-strength relations, or wear.

Another model to be considered in our study uses the structural reliability approach to perform a quantitative risk analysis (QRA). This approach has been used for structural design and, recently, for oilfield tubulars.[12,13] In principle, development of a structural reliability model involves a quantitative analysis of structural failures to compute risk followed by a calculation of risk-calibrated design factors. The factors are then used by structure designers. The structural reliability approach (particularly its analysis of failures) may provide an important technology-based component to the environmental risk model that is based on zoning.

Our analysis will also include economic models of risk relating the cost and risk of pipelines. Currently, such models are mostly qualitative [14,15] and either consider a total cost of pipeline's "life cycle" [14] or relate cost to some acceptable level of tolerable risk.[15] Also, the concept of risk in these models has been limited to the event of the pipeline's catastrophic rupture rather than continuous and small leakage. We will examine these techniques in view of their modification to include incidents of small leaks. Small leaks, or seeps, have little effect on performance of the petroleum transport process. However, they can be important in environmental pollution, particularly for near-shore areas adjacent to sensitive coastal wetlands. Also the risk of small leaks is an order of magnitude higher than that for large pipeline disruptions. This observation has been consistently supported by all statistics on pipeline spills. [16] Our work at this stage of the project will be to collect available statistics of pipeline leaks and combine the data with information regarding cost of cleanup and remediation, preferably in relation to the spillage size.

Transition-Flow Method for Leak Detection

The last part of our research will be a theoretical feasibility study of a new method for monitoring pipeline integrity using transition flow effects. Our working hypothesis for this method is that the physical process of changing flow pattern (transition) from a single to a two-phase flow in the pipeline generates a frictional effect that amplifies the change of pressure drop in the pipeline.[17] If the pipeline flow was designed such that a leak triggered transitional flow, the amplified change of pressure drop would be indicative of the leak. The question is, however, whether this change of pressure provides a significant signal (in terms of pressure gradient, or rate of pressure change) to be detected.

In this study we will mathematically simulate a leaking pipe using computational techniques that are currently used to model multiphase flow in pipes . We will perform a sensitivity analysis by varying operational and ambient conditions. We will then compare the calculated values of pressure signal and its distribution along the pipeline with performance of commercial sensors used in conventional leak detection techniques. The comparison will help us decide whether the new method would work and experimental testing in the future is needed.

RELEVANCE

This project will help Minerals Management Service to develop a consistent strategy for its new responsibility of preventing oil spills. The petroleum engineering expertise of the project's principal investigator and his familiarity with the petroleum industry will help to integrate technology-related data with other information derived from statistics, logistics, and management of pipeline systems. Additionally, the investigator's background in engineering science and his experience in modelling oilfield processes will ensure a quantitative rather than qualitative approach to the project's tasks such as the risk analysis of available technology; the analysis of causal association between technology, regulations and risk; and the development of a pipeline risk model.

This project will provide information necessary to consolidate and simplify pipeline regulations and remove disparities between regulatory agencies. A complicating factor under OPA is that state regulations for offshore pipelines are not preempted by federal oil prevention and spill response regulations. States may impose their own, more stringent requirements. The multiplicity of state and federal agencies with authority over pipeline safety holds the potential for inconsistencies in requirements, disparities in safety goals, differences in priorities, and redundancy of efforts. It also offers many areas of both mutual and parallel interest. Recommendations will be developed to consolidate and simplify the procedures required for regulatory compliance.

States administer coastal zone management plans (under the federal Coastal Zone Management Act) to mediate among competing uses of the waters and shore. Pipeline operators must therefore obtain permits in addition to those from MMS (and for pipelines crossing navigable waterways or coastlines, the U.S. Army Corps of Engineers and the U.S. Fish and Wildlife Services). This triple-level compliance system merely adds redundancy rather than a protection element to regulatory controls.

The project will identify management practices and regulatory requirements that are specific and pertinent to pipeline risk control in offshore and near-shore zones. At present, there are no consolidated measures for controlling pipeline risks in those zones. However, the current practices for controlling pipeline risk onshore are radically different from those for controlling pipeline risk offshore. This difference may result from different federal enforcement approaches, because onshore pipelines and offshore transmission pipelines are under OPS jurisdiction, while MMS regulates offshore production pipelines.

OPS leaves the inspection and maintenance of pipelines largely to the operators, enforcing its safety requirements with periodic audits of company records to ensure that operators meet OPS standards, which are very specific, when compared to MMS standards. At present, the MMS strategy of control is different from that at OPS. MMS inspectors make periodic on-site inspections of pipeline maintenance and safety systems during annual inspections of offshore facilities and spot inspections of construction and repair activities. During these inspections, all boarding, crossing, or departing pipelines are reviewed to ensure compliance with the terms of the MMS-issued permits.[18] However, the majority of MMS inspection focuses on non-pipeline matters such as fluid measurement, production, processing and well workover operations. A comparison of the inspection checklists reveals that the OPS list contains 400 items pertaining to pipelines, while the MMS list contains 30 such items.[2]

In near-shore and coastal zones pipeline systems regulated by these two agencies are physically and operationally connected. However, at present, regulatory standards applied to the same pipeline change considerably when the pipeline crosses the shoreline. Also the environmental risk of pipelines in near-shore and coastal waters is different from that of onshore and offshore pipelines. Hence, identifying specific practices and regulatory requirements for near-shore and offshore zones is essential.

The project will also advance the methodology of pipeline risk assessment. Presently, the suggested risk models are based on statistical data and mapping. It seems logical to integrate components of pipeline design and operation (technology) with the spatial component of pipeline location. Also, cost vs. benefit -- modeling of pipeline risk is necessary . The concept of using leak size to relate technology (cost) to cleanup and remediation (benefit), which will be examined in this study, is a basis for developing a cost-benefit model of pipeline risk.

Finally, the project will add new information to the continuing search for a technique to monitor pipeline integrity continuously and to detect leaks, particularly small (low rate) leaks. Because environmental technology of pipeline monitoring is in its early stages of development, most of the presently used techniques have been designed to detect only large leaks or catastrophic disruptions.

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Note about the author

Dr. Andrew K. Wojtanowicz is a professor of petroleum engineering at Louisiana State University. His research and academic activity consists of ten years with the Department of Petroleum Engineering at the University of Mining Metallurgy in Krakow, Poland; one and half years with the Department of Petroleum Engineering at New Mexico Institute of Mining and Technology; and 11 years at Louisiana State University. His research has covered various aspects of petroleum engineering including drilling and completion fluids, optimization, directional wells casing design, and environmental control technology (ECT) in petroleum engineering. He has authored and co-authored 33 refereed articles, 55 research papers, and three books.

Dr. Wojtanowicz's academic career has been intermittent, with over five years total oilfield experience. His expertise in drilling engineering was recognized internationally when he became an expert of the United Nations Technical Assistance Program in 1983. He also worked together with the United Nations team of drilling engineering specialists in Africa for two and a half years.

In view of the environmental program, the most valuable part of Dr. Wojtanowicz's industrial experience is his two and a half years employment as a drilling fluids technologist with the International NL Petroleum Services. At that time, he worked out of London, UK, and Madrid, Spain, on several land and offshore oilfield operations in Europe and Africa where he gained sound expertise in the treatment, handling, and disposal of oilfield fluids. After working for the oil industry overseas, Dr. Wojtanowicz returned to the academic setting with new concepts of environmental research and development in petroleum engineering.

Dr. Wojtanowicz organized the LSU Borehole Fluids and Environmental Control Laboratory for which he generated industrial support for the equipment and instrumentation. He began and has continued a long-term research program in petroleum environmental control technologies, ECT, that was substantiated by seven research contracts and three grants totalling over $550,000. He has also developed two environmental courses for petroleum engineers, "ECT of Drilling Engineering," and "Principles of Environmental Control in Petroleum Engineering."

In 1991 Dr. A Wojtanowicz was employed by Conoco Inc., as the Conoco Environmental Research Fellow. He spent one year with the company developing new technology for environmental management of drilling fluids.

Dr. Andrew K. Wojtanowicz is a registered petroleum and environmental engineer in the State of Louisiana.

Development of Improved Kick Tolerance Model for Deepwater Drilling Operations

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ABSTRACT

This paper describes ongoing research at LSU on an improved method for accurately estimating the maximum mud weight (hence the maximum depth) that could be safely drilled if well control operations became necessary on a floating drilling vessel operating in deep-water. The maximum mud density increase that can be handled without fracturing an exposed formation is called the kick tolerance of the well. As the kick tolerance decreases with increases in depth, the risk of formation fracturing during well control operations increases. Formation fracture often leads to an underground blowout that can be very expensive to control. Costs as high as $200,000,000 have been reported for control of a single underground blowout. In contrast, designing all deep-water wells with a high kick tolerance is quite expensive because of the large number of casing strings required. Another objective of this research is to develop appropriate criteria for evaluating risks and selecting appropriate values for minimum kick tolerance to be used in well design and while drilling.

An advanced kick simulator designed specifically for calculating kick tolerance for deep-water wells has been developed. The new software will also determine the kill capability (killable *kh* factor) of the available rig pumps.

Before an accurate kick tolerance simulator can be developed, experimental work is needed to determine the upward gas rise velocity and its distribution along the flow path during well control operations. The experiments (38 tests -- 8 with water and 30 with drilling fluid) will be conducted in the LSU No. 2 well that has a special completion that permits simulation of the gas kick. The well will be monitored by superficial sensors and four downhole pressure sensors. The measured data will be used in modeling the gas rise velocity and gas concentration profile along the upward flow.

The availability of this simulator will result in improved well design, safer drilling operations, and improved capability for drilling in deeper water depths.

INTRODUCTION

Geologists have long believed that significant hydrocarbon accumulations exist at deep-water locations, but economical and technical limitations have left these locations unexplored until recently.

The deep-water exploration and development concept have changed over the years. For example, in the early sixties the exploration and development of offshore hydrocarbons were restricted to 46 m (150 ft) by the physical and economic limitations of bottom-supported drilling and producing rigs. At this time, the major concern was to overcome this 50 m limit (hence, considered as a deep-water location).

The oil price jumped from $2.00 to $11.00 per barrel in the oil crisis of 1973. This was followed by the second oil price shock in 1979 when the oil price reached $30.00 per barrel. Motivated by these oil crises and the improved economics of oil exploration, the oil industry began searching for hydrocarbons in deeper water depths.

The definition of deep-water has changed as the technology has advanced. From moored semi-submersibles to today's advanced dynamic positioned (DP) vessels. Today, water depths above 400 m (1,312 ft) can be considered as deep-water. This limit is due to the current maximum depth that a human being can dive. Beyond this depth ROVs (remote operated vehicles) are used to service the well head at the sea floor. Furthermore, the ultra-deep water can be considered to be water depth above 1,000 m (3,281 ft).

Brazil is now one of the most active countries in deep-water drilling and producing. The deep-water drilling program using dynamic-positioned units began in 1985, when nine wells were drilled in water depth above 400 m (1,312 ft). In 1992 51 wells were drilled, as shown in Figure 1.

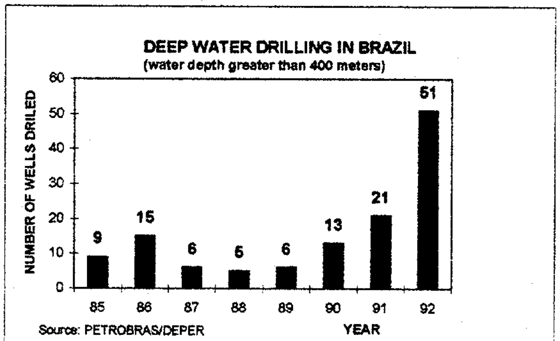

Figure 1 Deep-water wells drilled in Brazil

The deep-water drilling activities in Brazil were stimulated by the discovery of a giant field, Albacora, in September of 1984 by the wildcat well 1-RJS-297. Albacora field, located in Campos Basin (Southeast of Brazil) in water depths ranging from 293 m (755 ft) to 1,900 m (6,234 ft), has an estimated oil-in-place volume of 4.4 billion barrels over an area of 235 km^2 (90 mi^2).

In 1985, another giant field (Marlim) was discovered by the well 1-RJS-219A in a water depth of 853 m (2,797 ft). Marlim field is also located in Campos Basin in water depths ranging from 600 m (1,967 ft) to 1,050 m (3,445 ft). The total reserves (recoverable oil volume) for this field are estimated at 1.5 billion barrels of oil (6.6 million of oil-in-place) over an area of 132 km^2 (51 mi^2).

The exploration was not limited to the Albacora and Marlin fields. Prospecting in the Campos Basin soon pinpointed the Barracuda, Bijupirá and Salema fields with reserves of 106, 43, and 13 million barrels of oil, respectively, in water depths ranging from 400 m (1,312 ft) to 1,000 m (3,281 ft). In addition, other deep-water prospects are being drilled, outside the Campos Basin, which may discover new deep-water fields.

The new challenge after these discoveries was how to overcome the technology barriers to producing these deep-water fields. Exploratory offshore drilling in Brazil started in 1968, in the shallow water of Sergipe/Alagoas Basin (Northeast of Brazil), that led to the discovery of the Guaricema field in the second well drilled. Guaricema field was the first offshore field produced in Brazil. In 1977, using floating production system (FPS) technology that was used for the first time in Brazil, Enchova field came on stream. Due to the simplicity of the FPS, the lead-time needed to bring this field on stream was reduced. The success of the Enchova production experience, and others that followed, led to expanded use of FPS to accelerate the production of new fields.

The next step was implementing subsea completion techniques and extending the application of FPS for field development. In 1979, the 1-RJS-38 well was the first to be subsea completed in a water depth of 189 m (629 ft).

The first diverless technique was applied in the completion of the well 3-PU-2 in 1984. This technique was not efficient for well-tie-in (connection between well and the production apparatus). Therefore, in 1987, the first diverless lay-away Christmas tree (the production and control lines are lowered together with the subsea control valves) was run at Marimbá field, well 1-RJS-294, in a water depth of 411 m (1,348 ft). The world water depth record for subsea completion was repeatedly broken in a short period of time. Culminating in the current world record of 1,027 m (3,370 ft) established in May of 1994 by well 3-MRL-4, in Marlim field, as shown in Figure 2. Of all subsea trees installed worldwide, one third have been installed in Brazil.

Deep water drilling poses special problems such as low fracture gradients, high pressure loss in choke lines, overbalanced drilling due to a riser safety margin, generally high permeability formations, and emergency riser disconnection problems. As a result, new techniques and more reliable models must be developed to assist in well design criteria, kick detection, well control operations, and blowout contingency planning.

Key factors to successfully drilling deep-water wells are (a) a detailed well design and drilling plan and (b) close control while drilling to avoid kick, loss of circulation, and underground blowout. An underground blowout can be especially costly and is highly undesirable.

The kick tolerance concept has been shown to be a powerful tool that can be used during well design, along with the pore pressure and fracture gradients, to determine casing setting depths. In addition, kick tolerance can be used while drilling to estimate the fracture risk of the weakest exposed formation, if a kick was taken and circulated, that could lead to an underground blowout. Considering this parameter, the decision to anticipate the running of casing can be made. Furthermore, it can be a parameter of interest to governmental regulatory agencies, such as the Mineral Management Service in the US for regulating drilling activities.

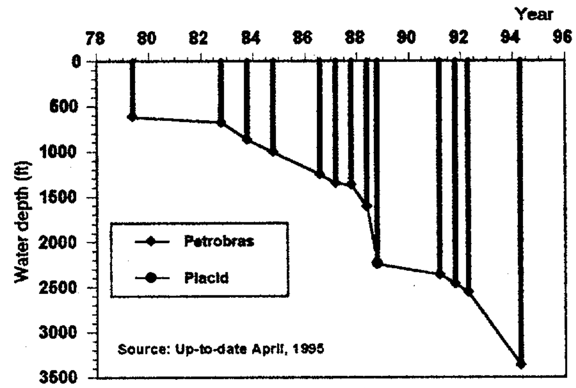

Figure 2 World record for subsea completion

Even though kick tolerance has been used in the drilling industry, the concept has been controversial[1]. Much confusion can be credited to the original definition: "difference between mud weight in use and formation pressure (expressed as mud weight equivalents) against which the well could be safely shut in without breaking down the weakest formation." For example, with a pressure integrity test at the casing shoe of 1.68 gr/cm^3 (14 lb/gal) and a mud density of 1.20 gr/cm^3 (10 lb/gal), many may consider that they are secure because they have a kick tolerance of 0.48 gr/cm^3 (4 lb/gal). This is only true if no influx (zero pit gain) occurs, but generally a kick is detected by the pit gain (increase of volume in the mud pits).

As a result, kick tolerance decreases as kick volume and depth increase. It is calculated assuming that natural gas (worst case) is the kick fluid. Also assumed is the maximum pit gain that would be expected before the blowout preventers are closed. The maximum pit gain used in the calculation is critical and must be appropriate for field operating practices, instrumentation, and rig crew training. Shut-in kick tolerance applies to well conditions when the well is shut in. Circulating kick tolerance applies to the most severe conditions expected during the well control operations to remove the kick fluids from the well.

The circulating kick tolerance can easily be calculated as a simple model that assumes the influx of gas enters as a slug and remains as a slug during the circulation. This simple model, although easy to calculate, is very conservative if compared with a modern kick simulator as shown in Figure 3 (example of a deep water well in Brazil[2]).

In contrast, calculation of kick tolerance by existing kick simulators can be very time consuming.

For example, it took almost one day to calculate five points to draw the upper curve in Figure 3. Although time consuming, using the kick simulators to calculate kick tolerance in this well saved around $100,000 in drilling costs. Thus, a less conservative, more realistic, reliable, faster kick simulator dedicated to calculate kick tolerance is desirable not only for use in well planning but also while drilling.

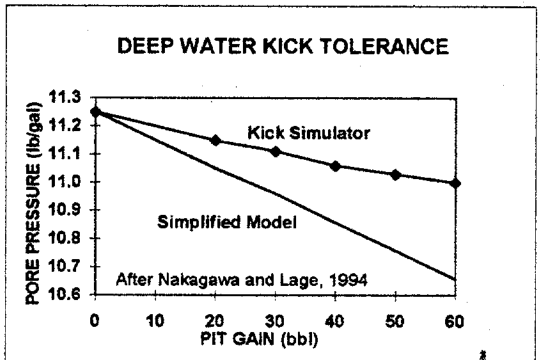

Figure 3 Kick Tolerance for deep-water

The determination of the gas rise velocity in annuli for various wells conditions is crucial and fundamental to the development of a more accurate kick tolerance calculation procedure. Despite many studies in this area with flow loops or a real well (using mud, Xantham gum, or water as a liquid phase and air, Nitrogen, or Argon gas as a gas phase), the necessary gas distribution profile still can not be reliably estimated. We now have some idea about the bubble front velocity, volume centered velocity, and the tail velocity, but how the shape of the distribution profile will change with time during the gas migration is unknown. Since the tail velocity is low, its volume along the well can be considerable. Consequently, experiments to determine these velocities and distribution profiles have to be done.

The concept of kick tolerance is more complex in deep water drilling since dynamic position drilling ships (DPDS) are used, and normally a riser safety margin is applied to avoid an eventual loss of hydrostatic pressure due to an emergency disconnection and BOP failure. Depending on water depth, leak-off test results, and pore pressure, the riser margin cannot always be applied because of the risk of formation fracture. The kick tolerance value can be near zero or even negative, without implying a dangerous situation, in this case.

Another important factor in deep-water is the high pressure loss in the long subsea flow lines. This factor has to be included in the kick simulator.

Under certain conditions, a greater risk of an underground blowout can be tolerated if it is known that control of the well could be regained using available rig equipment. The chance of being able to regain control of the well is estimated by calculating the product of permeability, k, and permeable zone thickness, h, which could be controlled using a dynamic kill procedure and the available rig pumps. The "killable kh" is routinely calculated by some operators[3,4] as drilling progresses. If it is determined that an underground blowout is not likely or that if one did occur it could be controlled with available rig equipment, a deeper casing setting depth may be selected. When the number of casing strings can be reduced, significant cost savings can be achieved without taking unacceptable risks of an underground blowout. One oil company[4] has successfully developed and applied the concept of killable kh when drilling multiple objectives under variant pore pressure conditions.

As a result, an advanced kick simulator that is dedicated to kick tolerance and killable kh calculations for deep water drilling is needed. It is important that the developed software be fast, reliable, and suitable for available rig site computers. Experiments have to be performed to determine the gas distribution profile in the annuli, and how the shape of the distribution profile will change along the path of upward migration. In addition, the effect of high pressure losses in the kill line has to be incorporated into the model. Also the killable kh factor should be an output of the computer program.

CIRCULATING KICK TOLERANCE MODEL

A mathematical model of a kick simulator dedicated to calculate the circulating kick tolerance is presented here. The proposed model is divided into submodels: a wellbore model, gas reservoir model, choke line model, and upward gas rise velocity model.

Wellbore Model

The wellbore unloading model includes the upward two-phase flow inside the annulus (well/drillstring, casing/drillstring, and riser/drillstring). This model was proposed by Nickens[5].

The model is based on: a) mass-balance equations (continuity equations) for the mud and gas, b) a momentum-balance equation for the gas-mud mixture, c) equation of state for mud and gas, and d) a correlation relating the gas velocity to the average mixture velocity plus the relative slip velocity between mud and gas to be determined in an experimental work.

Continuity Equations

The continuity equation is founded on the principle of mass conservation. Under unsteady two-phase flow conditions, the liquid phase continuity equation is given by:

$$\frac{\partial H}{\partial t} + \frac{\partial (v_l H)}{\partial z} = 0 \tag{1}$$

where liquid holdup H is defined as:

$$H = \frac{\text{volume of liquid in an annular segment}}{\text{volume of annular segment}} \tag{2}$$

and for the gas phase is given by:

$$\frac{\partial\left[\rho_g(1-H)\right]}{\partial t}+\partial\frac{\left[v_g\rho_g(1-H)\right]}{\partial z}=0 \tag{3}$$

Momentum Balance Equation

The momentum balance equation is based on Newton's second law of motion which states that the summation of all forces acting on a system is equal to the rate of change of momentum of that system. For two-phase flow the momentum balance equation is given by:

$$\frac{\partial\left[v_l\rho_l H+\left(v_g\rho_g(1-H)\right)\right]}{\partial t}+\frac{\partial\left[v_l^2\rho_l H+\left(v_g^2\rho_g(1-H)\right)\right]}{\partial z}+\frac{\partial p}{\partial z}+\left(\frac{\partial p}{\partial z}\right)_{elev}+\left(\frac{\partial p}{\partial z}\right)_{fric}=0 \tag{4}$$

where $(\partial p/\partial z)$ is the gradient pressure.

The elevation term or hydrostatic pressure gradient is given by:

$$\left(\frac{\partial p}{\partial z}\right)_{elev}=\frac{g}{g_c}\left[\rho_l H+\rho_g(1-H)\right] \tag{5}$$

The friction term or frictional pressure gradient is calculated using the Beggs and Brill's[6] correlation modified to account for the non-Newtonian characteristic of drilling fluids.

The two-phase flow friction factor f_{tp} is given by:

$$f_{tp}=f_F\,.\,e^s \tag{6}$$

where the no-slip friction factor f_F is obtained from a Fanning diagram (Craft et al[7]). The no-slip friction factor used by Beggs and Brill was for a smooth pipe curve on a Moody diagram.

The ratio of the two-phase slip to no-slip friction e^s is calculated as:

$$s=\frac{\ln\frac{\lambda}{H^2}}{-0.0523+3.182\ln\left(\frac{\lambda}{H^2}\right)-0.8725\left[\ln\frac{\lambda}{H^2}\right]^2+0.01853\left[\ln\frac{\lambda}{H^2}\right]^4} \tag{7}$$

where the no-slip liquid holdup or input liquid content λ is defined as:

$$\lambda=\frac{q_l}{q_l+q_g} \tag{8}$$

If λ/H^2 is greater than 1.2 or less than 1.0 then the exponent s is calculated from:

$$s=\ln\left(2.2\frac{\lambda}{H^2}-1.2\right) \tag{9}$$

The frictional term is calculated from:

$$\left(\frac{\partial p}{\partial z}\right)_{fric}=\frac{f_{tp}\rho_{ns}v_m^{\,2}}{2g_c d} \tag{10}$$

where the mixture velocity v_m is defined as:

$$v_m=v_l H+v_g(1-H) \tag{11}$$

and the two-phase no-slip density ρ_{ns} is defined as:

$$\rho_{ns}=\rho_l\lambda+\rho_g(1-\lambda) \tag{12}$$

Equation of State

Since in deep-water drilling only water-based mud is used, because of environmental pollution problems in case of an emergency disconnection of riser, the drilling fluid can be considered incompressible. Although Hoberock et al[8] showed that even in water-based mud the pressure and temperature can cause an error by hundreds of psi in deep wells when compared with the pressure calculated using constant surface densities. The reduction in bottom hole pressure for well depths up to 4,572 m (15,000 ft) is not so sensitive, and the mud density can be considered as incompressible in this study. In a case of deep-well drilling or if oil-based mud is used, effects of temperature and pressure should be considered (Ekwere et al[9]). Therefore, the density of mud is given by:

$$\rho_l=\text{constant} \tag{13}$$

As for the gas density, a real gas equation of state is given by:

$$\rho_g=\frac{pM}{zRT} \tag{14}$$

Gas Reservoir Model

Since little is primarily known about the properties of the gas reservoir during well design or while drilling, a detailed reservoir model is not usually justified.

Thomas et al (in Element et al[10]) introduced the use of equation:

$$q_{g_{sc}} = \frac{\pi k h T_{sc}}{(\mu z T)_f p_{sc} P_D}\left(p_f^2 - p_{bh}^2\right) \quad (15)$$

where:

$$P_D = \frac{1}{2}\ln(t_D + 0.809) \quad (16)$$

$$t_D = \frac{kt}{\phi \mu_f c_f r_w^2} \quad (17)$$

The approximate solution (equation 15) of the diffusivity equation requires the assumption of a constant gas flow rate. Since during a gas kick the bottom hole pressure and fluid flow rate vary , this assumption is not true.

Nickens made a slight modification in the Equation 15. He divided the gas formation into axial segments of thickness h_i equal to the rate of penetration (ROP) times the timestep in use. Then he considered that each segment flows independently of the other. As a result, the total gas-influx rate is then:

$$q_g = \sum_{i=0}^{N(t)} q_{gi} \quad (18)$$

where $N(t)$ is the number of segments at time t. This modification to the flow equation removes the approximation that gas flow is axially symmetric within the exposed gas.

Implicit, also, is that the reservoir extends to infinity. In most kick control situations this assumption is acceptable because the gas flow time is short, and the reservoir boundary is not reached. Although simulation of small pocket of gas is not accurate, an extended under ground blowout is not lilely in this situation.

Choke Line Model

A choke line is employed to carry fluids to the surface after the subsea blowout preventers (BOP) are closed. The long and narrow (3 in) choke line in deep-water leads to high velocity and consequently high pressure loss.

Elfaghi[11] did an experimental work at LSU using a full-scale model consisting of 914 m (3,000 ft) of 60 mm (2 3/8 in.) subsurface choke line. For single phase mud flow, both the Bingham plastic and the power law non-Newtonian models provided acceptable comparison with observed data. For two-phase flow through the choke line, Hagedorn and Brown[12] and Beggs and Brill correlations provided acceptable comparison with observed data.

Therefore, the two-phase flow through the choke line and annulus was modelled using Hagedorn and Brown with the appropriate equivalent diameter for the annulus.

Upward gas rise velocity model

The development of a reliable kick simulator needs an accurate model of gas-mud mixture flow as it moves upward in the wellbore. The empirical correlation relating the gas velocity to the average mixture velocity plus the relative slip velocity will be determined in an experimental work.

The Petroleum Engineering Department of Louisiana State University has been conducting a project in well control at the Petroleum Engineering Research and Technology Transfer Laboratory for more than a decade. Most of the experiments cited in this section were performed at this well facility.

Rader et al[13] verified that the assumption of gas flowing as a continuous slug and with the same velocity as the liquid did not work well when applied in a 1,828 m (6,000 ft) LSU research well. They observed lower gas velocity and lower casing pressure than expected during a well control operation.

When evaluating some kick control methods Matheus and Bourgoyne[14] reported the occurrence of bubble fragmentation. He observed that the bubble fragmentation is smaller in viscous fluids and less intense in the dynamic volumetric method.

Caetano[15] studied two-phase flow in a flow loop with flow of air-water and air-kerosene. He defined flow pattern maps for concentric and fully eccentric geometry. He concluded that the eccentricity affects the friction factor and the transition from bubble to slug flow. Furthermore, he proposed models for liquid hold up and pressure gradients for each flow pattern based on Taitel's[16] equations.

Motivated by the need for a better knowledge of bubble fragmentation process, Bourgoyne and Casariego[17] made a theoretical and experimental study of gas kick in vertical wells. Their model closely predicted measured casing pressure from a 1,828 m (6,000 ft) LSU research well.

Rommetveit and Olsen[18] used an inclined (maximum of 63^0) research well to perform gas kick experiments using Nitrogen and Argon gas with oil-base mud. They used 9 surface sensors to monitor the pump strokes, mud return flow rate, pit level, choke position, choke pressure, gas injection rate, choke line fluid density, standpipe pressure, and gas injection pressure. In addition, they used one hardwire sensor and four downhole memory tools to log the pressure and temperature. Based on the differential pressure among the sensors in the well and among the choke pressure and the sensors in the well they concluded that: a) the gas starts to dissolve immediately as it enters the wellbore; b) the bubble flow regime prevails in the two-phase section; c) the gas bubbles rise and dissolve; d) the initial gas-oil ratio (GOR) in the experiment was higher than the saturated GOR; e) gas bubbles rise and distribute over a longer section of the well; f) the gas dissolution is governed by convective diffusion, and the mud does not become saturated with gas immediately. They also observed some pulsations on the return flow, and their explanation was that gas bubbles first coalesce and form a slug of gas which rises fast and expands. After this a new dissolution process takes place in the upper part of the annulus.

Continuing well control research at LSU, Nakagawa and Bourgoyne[19] performed an experimental study in a fully eccentric flow loop at different inclinations to determine the gas fraction and gas velocity during the gas kick. They presented a simplified model for the gas-rise velocity eliminating the bubble size and shape for the calculation. Following this study, Mendes[20] and Wang[21] continued Nakagawa's experiments with lower superficial gas and liquid velocities which were not covered in previous experiments.

Using a flow loop, Johnson and White[22] performed some experiments to examine gas rise velocities during kicks. They used water and Xantham gum as a liquid phase and air as the gas phase. They concluded that in drilling fluids the bubbles rise faster than in water despite the increased viscosity. They explained that these surprising results are due to the change in the flow regime with large slug type bubbles forming at lower void fractions. Furthermore, their results show that a gas influx will rise faster than any previously published correlation would predict. One of their results, for vertical flow, is shown in a Zuber-Findlay[23] plot along with Nakagawa's, Mendes', and Wang's data in Figure 4. We can observe from this figure that Johnson's and Nakagawa's data are similar and can be fitted in a Zuber-Findlay correlation for the mean velocity of gas (v_g.)

$$v_g = C_0 v_m + v_s \tag{19}$$

where the superficial mixture velocity (v_m) is defined as:

$$v_m = v_{gs} + v_{ls} = \frac{q_g + q_l}{A_{an}} \tag{20}$$

Hovland and Rommetveit[24] experimented with gas kick in the same well used by Rommetveit and Olsen. In these experiments the authors used oil and water-based mud. The Nitrogen and Argon were injected to simulate the gas kick. They varied mud type, mud density, gas concentration, mud flow rates, and gas injection depth in their experiments. They concluded that in a high concentration gas kick, the gas rises faster than in low and medium concentration. The gas rise velocity correlations obtained from these experiments are not significantly dependent on gas void fraction, mud density, inclination, mud rheology, and surface tension. They presented one Zuber-Findlay plot, but the graphic had been normalized (divided by the maximum value). As a result, the experimental data cannot be compared with previous work.

Utilizing the same flow loop used by Johnson and White, Johnson and Cooper[25] investigated the effects of deviation and geometry on the gas migration velocity. For vertical orientation they concluded that the flow in the pipe and annulus are almost the same. The gas distribution coefficient (C_0) is the same while the gas slip velocity (v_s) is slightly larger in the annular geometry. In deviated flows C_0 is larger for the annulus and v_s is larger for the pipe. Up to a deviation of 45° v_s remains almost constant. They also concluded that even in a stagnant mud, the gas normally migrates at a velocity over 0.5 m/s (5,900 ft/hr), almost six times the conventional field model of 0.085 m/s (1,000 ft/hr). The conventional field model considers only the hydrostatic effect of gas migration as:

$$\frac{dp_c}{dt} = \rho_m g v_s \tag{21}$$

where dp_c/dt is shut-in pressure rise rate.

To calculate the gas rise velocity, an equation developed by Johnson and Tarvin[26] to calculate the shut-in pressure rise rate (dp_c/dt) was used:

$$\frac{dp_c}{dt} = \frac{X_k V_k \rho_m g v_s - q_e}{X_k V_k + X_w V_w + X_m V_m} \tag{22}$$

The Equation 22 considers the mud and wellbore compressibility and fluid loss into the formation.

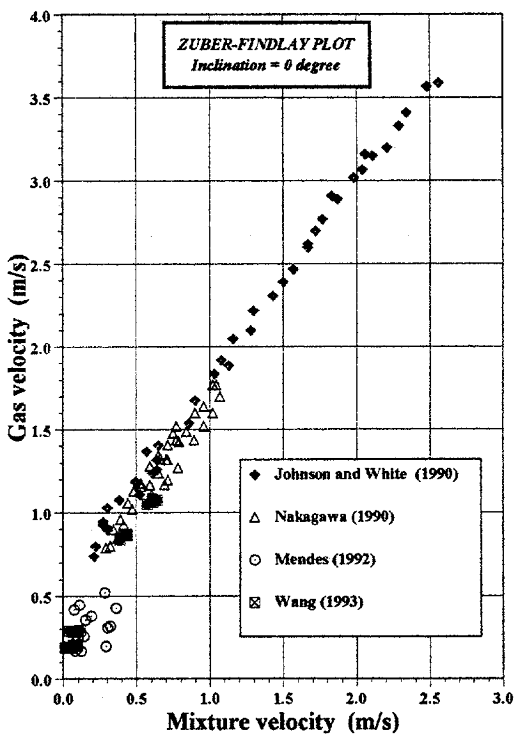

Figure 4. Zuber-Findlay plot for flow-loop experiments

Lage et al[27] reported gas kick experiments performed in a 1,310 m (4,298 ft) vertical training well. The well has a 400 mm (13 3/8 in) casing set at 1,310 m and cemented up to surface. Inside this case, a 178 mm (7 in) casing, is placed to simulate the wellbore. A tubing of 48 mm (1.9 in) was used to inject the air at the bottom of the 178 mm casing passing through the annulus of 400 mm x 178 mm. In this same annulus an additional 48 mm tubing was placed at 800 m (2,625 ft) to simulate the casing shoe and circulation losses. Inside the 178 mm casing a drillstring composed with 121 mm (4 3/4 in) drill collars and 89 mm (3 1/2 in) drill pipes were run. A special sensor sub was made to accommodate the pressure sensor. Four sensors were placed at 302 m (991 ft), 600 m (1,968 ft), 877 m (2,877 ft), and 1,267 m (4,157 ft). Air and water were used in four tests. They measured three velocities: bubble front, volume centered, and bubble tail. If no gas is present between two sensors, the differential pressure is equal to hydrostatic pressure between them. The bubble front velocity can be measured dividing the distance between two upper sensors and the time elapsed between the beginning of differential pressure decrease in the two upper sensors and two lower sensors. Next, to measure the volume centered velocity they assumed that the center of the largest gas volume (when the differential pressure is minimum) is at the middle point of two sensors. They assumed that the air expansion and concentration changes are negligible when the volume of air rises from the center of two lower sensors to the center of the pair above. Therefore, the volume centered velocity can be measured dividing the distance between the lower and upper pair of sensors and the time elapsed between the minimum differential pressure between the lower and upper pair of sensors. The tail velocity was measured considering the distance and differential pressure stabilization between two sensors. They observed that no significant difference was obtained among the velocities for open or shut-in well conditions. They obtained an average bubble front velocity of 0.26 m/s (3,070 ft/hr), an average tail velocity of 0.09 m/s (1,063 ft/hr), and an average volume centered velocity of 0.08 m/s (944 ft/hr) to 0.15 m/s (1,772 ft/hr). In addition, they derived an interactive equation for pressure build-up (choke pressure) prediction that fit very well with the experimental data:

$$p_c = \frac{1}{X_m} \ln \frac{V_w - V_k}{V_w + V_f - \frac{\rho_k V_k}{p_c}} \tag{23}$$

SOLUTION OF THE DIFFERENTIAL EQUATIONS

The solution of differential equations is achieved using the numerical method of finite difference. This method was used by Nickens. There are many techniques to solve the differential equation by finite difference method. The "centered in distance and backward in time with a fixed space grid technique" was adopted in this study. The flow path is divided into a finite number of cells. Figure 5 shows a cell for two different time step.

The finite difference formulation for the continuity equation in the space derivative is approximated by:

$$\frac{\partial U}{\partial z} = \frac{U_6 - U_5}{\Delta z} \tag{24}$$

and the time derivative by:

$$\frac{\partial U}{\partial t} = \frac{U_4 - U_3}{t} = \frac{U_6 + U_5 - U_2 - U_1}{2\Delta t} \tag{25}$$

where U is a function of z and t. Substituting these approximations into Equations (1) and (3), the finite difference formulation for the continuity equation for liquid became:

$$\frac{(v_l \rho_l H)_6 - (v_l \rho_l H)_5}{\Delta z} + \frac{(\rho_l H)_6 + (\rho_l H)_5 - (\rho_l H)_2 - (\rho_l H)_1}{2\Delta t} = 0 \tag{26}$$

and for gas to:

$$\frac{\left[v_g \rho_g (1-H)\right]_6 - \left[v_g \rho_g (1-H)\right]_5}{\Delta z} + \frac{\left[\rho_g (1-H)\right]_6 + \left[\rho_g (1-H)\right]_5 - \left[\rho_g (1-H)\right]_2 - \left[\rho_g (1-H)\right]_1}{2\Delta t} = 0 \tag{27}$$

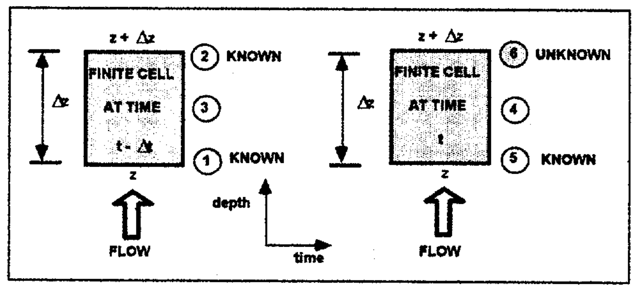

Figure 5. Finite difference scheme for a cell

The finite difference formulation for the momentum balance equation for the time derivative is the same as Equation (25), but the spatial derivative becomes:

$$\frac{\partial U}{\partial z} = \frac{U_6 + U_2 - U_5 - U_1}{2\Delta z} \tag{28}$$

and substituting Equation (28) into Equation (4) gives:

$$\frac{1}{2\Delta z}\Big\{\left[v_g^2 \rho_g (1-H)\right]_6 + \left[v_g^2 \rho_g (1-H)\right]_2 - \left[v_g^2 \rho_g (1-H)\right]_5 - \left[v_g^2 \rho_g (1-H)\right]_1 +$$
$$+ \left(v_l^2 \rho_l H\right)_6 + \left(v_l^2 \rho_l H\right)_2 - \left(v_l^2 \rho_l H\right)_5 - \left(v_l^2 \rho_l H\right)_1\Big\} + \frac{1}{2\Delta t}\Big\{\left[v_g \rho_g (1-H)\right]_6 +$$
$$+ \left[v_g \rho_g (1-H)\right]_5 - \left[v_g \rho_g (1-H)\right]_2 - \left[v_g \rho_g (1-H)\right]_1 + (v_l \rho_l H)_6 + (v_l \rho_l H)_5 -$$
$$- (v_l \rho_l H)_2 - (v_l \rho_l H)_1\Big\} \frac{p_5 - p_6}{\Delta z} + \frac{1}{4}\left[\left(\frac{\Delta p}{\Delta z}\right)_1 + \left(\frac{\Delta p}{\Delta z}\right)_2 + \left(\frac{\Delta p}{\Delta z}\right)_5 + \left(\frac{\Delta p}{\Delta z}\right)_6\right]_{fric} -$$
$$- \frac{1}{4}\left[\left(\frac{\Delta p}{\Delta z}\right)_1 + \left(\frac{\Delta p}{\Delta z}\right)_2 + \left(\frac{\Delta p}{\Delta z}\right)_5 + \left(\frac{\Delta p}{\Delta z}\right)_6\right]_{elev} = 0 \tag{29}$$

The calculation of the flow properties at point 6 in Figure 5 from those known properties at point 1, 2, and 5 require an iterative procedure. Points 1 and 2 represent the flow properties at the previous time step (t - Δt) in lower and upper boundaries respectively. Points 5 and 6 represent the same points as 1 and 2 but at the time step t. Points 3 and 4 represent arithmetic averaging at the center of the cell at $t - \Delta t$ and t time steps, respectively.

The discretization procedure is only applied to the two-phase region. A single cell exists the first time, two cells for the second time and so on. The process for each time step starts in the top cell and ends in the bottom cell that coincides with the bottom of the well. Using this procedure the pressure at any given time step and position can be determined.

EXPERIMENTAL PROGRAM

The procedure for determination of upward gas rise velocity and distribution factor during well control operations is presented here.

Despite many studies in this area with flow loops and wells (using mud or Xantham gun as the liquid phase, and air, Nitrogen, or Argon gas as the gas phase), the necessary gas distribution profile still can not be reliably estimated. Furthermore, in the literature reviewed, we have not found an experiment that has used a full scale well with natural gas as a gas phase.

We now have some idea about the bubble front velocity, volume centered velocity, and the tail velocity. However, how the distribution profile will change with time during the upward gas migration is unknown. Since the tail velocity is low, its volume along the well, mainly in high viscosity mud, can be considerable.

Description of a full-scale well: LSU No. 2

The experiments will be carried out in the existing LSU No. 2 well, located at the Petroleum Engineering Research and Transfer Laboratory in Baton Rouge, Louisiana. The LSU No. 2 well is a vertical well which is 1,793 m (5,884 ft) deep and cased with 244 mm (9 5/8 in) casing. The well is completed with a 32 mm (1 1/4 in) gas injection line runs concentrically in a 89 mm (3 1/2 in) drilling fluid injection line. The well also contains 60 mm (2 3/8 in) perforated tubing which serves as a guide for well logging tools to be run in the annulus without risk of the logging cable wrapping around the drill string and becoming stuck.

Methodology of experiments

A drilling fluid composition matching those utilized to drill deep-water wells in the Campos Basin, offshore of Brazil, and natural gas will be utilized.

The gas will be injected at the desired injection rate through the 32 mm (1 1/4 in) tubing. Drilling fluid will be circulated down the annulus between the 89 mm (3 1/2 in) and 32 mm (1 1/4 in) tubings at the desired mud flow rate with returns taken from the 244 mm (9 5/8 in) casing.

During the experiments the drill pipe, casing and gas-injection pressures at the surface will be continuously monitored. The mud rate and the gas rate into and out of the well will be measured. One wired-to-surface downhole pressure sensor and three downhole pressures recording sensors will monitor the pressures developed during the well control experiments. A pressure signal will be generated at the beginning of the experiment to synchronize in time all four sensors. To investigate the concentration of gas in the tail of the multiphase region, samples of mud will be caught downstream of the separator after the major gas volume is circulated. The samples will then be analyzed to determine the concentration of the gas present in the mud.

Methodology to measure gas rise velocities

It is anticipated that the velocity of the kick front, velocity of the peak gas concentration, and the velocity of the tail of the two-phase region will be estimated through an analysis of the measured differential pressures. If no gas is present between two consecutive pressure sensors and mud is not being circulated, the differential pressure should reflect the hydrostatic pressure between them. When mud is being circulated, the differential pressure between two sensors should be equal to the sum of the hydrostatic pressure and the pressure losses between them.

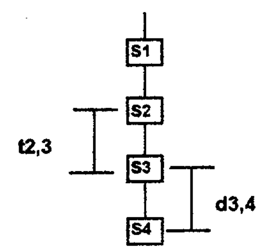

Figure 6. Downhole pressure sensors disposition

When the gas front reaches each sensor, the differential pressure begins to decrease denoting the arrival of the bubble front. Thus, the velocity of the front can be estimated by dividing the distance between sensors by the elapsed time between the first arrival of the front. For example, from the Figure 6, the bubble front velocity between sensors 3 and 4 can be estimated knowing the distance $d_{3,4}$ and the time elapsed between the observed initial decrease in differential pressure between sensors 2,3 and sensors 3,4 using the following equation:

$$v_{front} = \frac{d_{3,4}}{\left(t_{2,3ini\Delta p} - t_{3,4ini\Delta p}\right)} \tag{30}$$

Similarly, the tail velocity can be calculated as the distance between two sensors (for example, sensor 2 and 3) divided by the elapsed time to stabilize two adjacent differential pressures.

$$v_{tail} = \frac{d_{2,3}}{\left(t_{3,4stab\Delta p} - t_{2,3stab\Delta p}\right)} \tag{31}$$

The study of the tail concentration with its lower velocity may show a large volume of gas inside the well that many previous investigators may have overlooked.

When the differential pressure between two sensors is a minimum, the largest amount of gas is present between the sensors, but the exact position of the peak concentration is not known. Therefore this should be investigated in this study. If it is assumed that the peak concentration occurs at the mid-point between two sensors, then the velocity of peak concentration can be computed as the distance between two mid points (e.g. between mid-point of sensors 3 and 4, and mid-point of sensors 2 and 3) divided by the elapsed time between them when the minimum values of differential pressure were recorded in the two adjacent well segments:

$$v_{center} = \frac{\frac{d_{3,4}}{2} - \frac{d_{2,3}}{2}}{t_{4,3_{\min\Delta p}} - t_{2,3_{\min\Delta p}}} \tag{32}$$

Since it will be possible to move the pressure sensors while the experiments are underway, it will be possible to verify if the above assumptions are justified. A more exact location of the peak concentration can be found by placing two pressure sensors closer together. After the peak concentration passes the location of the sensors, the sensors can be pulled to shallower depth to wait for the peak concentration to reach this new location.

After eight experiments with water and gas, thirty experiments are planned with drilling fluid and natural gas.

The main parameters varied in the experiments will be gas injection rate, pit gain volume, mud circulation rate, and drilling fluid yield point.

GAS DISTRIBUTION PROFILE

Using the experimental data, we expect to determine how the shape and the gas distribution profile along the well will change with time during the upward flow. Since the tail velocity is low, if compared with the leading edge velocity or front velocity, its volume along the may can be considerable.

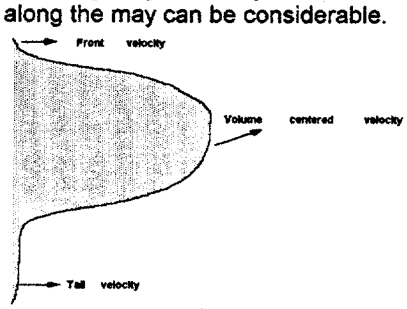

Figure 7. Gas distribution profile

If the gas distribution profile is successfully determined, the calculations for the kick simulator dedicated to calculate kick tolerance can be simplified.

KILLABLE *kh*

Although an underground blowout is highly undesirable, necessary unconventional well-control contingency plans can be developed for a hole section with a known but manageable underground flow potential. Wessel and Tarr[3] reported a new strategy to optimize well costs by managing the well-control risks better than an arbitrary minimum kick tolerance. A direct tradeoff exists between kick tolerance and well cost. Specifying a higher kick tolerance than necessary can increase the well cost because additional casing strings will be required. Specifying lower kick tolerance can lead to costly well-control incidents. The authors first simplified the productivity index (J) as a function of only the product of the permeability (k) and the permeable zone thickness (h).

$$J = \alpha k h \tag{33}$$

By estimating the kh value for a potential gas zone to be drilled, one can determine whether an underground gas flow can be controlled with the available rig equipment or whether an additional pumping unit or a relief well will be required. Furthermore, neglecting the two-phase-flow liquid hold up and any friction pressure loss in the annulus, the kill-mud density and pump rate combination required to kill the underground flow is dependent on the volume of kill-mud available as shown in Figure 8.

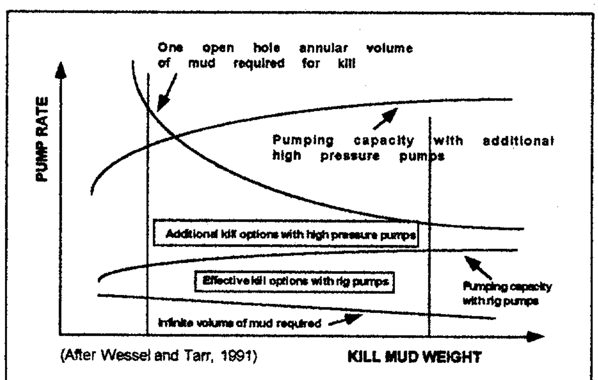

Figure 8. Pump-rate requirements and equipment limits

CONCLUSION

Even though many experimental works in full-scale wells were accomplished, few results are published. None of the previous works had experiments for a combination of full-scale well and natural gas.

Moreover, the gas rises velocity and how the distribution profile varies with time are essential to the correlation of any kick simulator.

Kick tolerance concept has shown to be a powerful parameter to use in well design, during drilling, and for agencies that regulate the drilling activities. Therefore, kick tolerance should be used frequently, and its use should be facilitated by a computer program.

Deep-water drilling and production are a reality today. Due to its intrinsic problems such as, low fracture gradients, high pressure loss in a long choke line, overbalanced drilling due to a riser safety margin, generally high permeability formations, and emergency riser disconnection problems, new techniques or more reliable models must be developed to assist in well design criteria, kick detection, well control, and blowout contingency planning.

The availability of the kick simulator dedicated to calculate kick tolerance will result in improved drill planning, safer drilling operations, and improved capability for drilling in deeper water depths.

ACKNOWLEDGMENT

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NOMENCLATURE

Roman Letters

A_{an}= cross sectional area of annulus
c_f = formation compressibility
C_0 = gas distribution factor
d = distance
dp_c/dt = shut-in pressure raise rate (choke pressure)
e^s = ratio of the two-phase slip to no-slip friction factor
f_F = no-slip Fanning friction factor
f_{tp} = two-phase flow friction factor
g = gravitational acceleration
g_c = conversion factor
h = permeable zone thickness
H = liquid holdup
J = productivity index
k = permeability
M = gas molecular weight
p = pressure
p_{bh} = bottom-hole pressure
p_c = choke pressure
P_D = dimensionless pressure
p_f = formation pore pressure
p_{sc} = pressure at surface condition (standard condition)
q_e = average filtrate loss rate to formation
q_g = gas flow rate
q_{gsc}= gas flow rate at standard conditions
q_l = liquid flow rate
R = gas constant
r_w = wellbore radius
t = time
T = temperature
t_D = dimensionless time
T_{sc} = temperature at surface condition (standard condition)
v_{center} = volume centered gas velocity
V_f = fluid loss volume
v_{front} = gas front velocity
v_g = mean gas velocity
v_{gs} = superficial gas velocity
V_k = influx volume
v_l = liquid velocity
v_{ls} = superficial liquid velocity
v_m = mixture or homogeneous velocity
V_m = mud volume
v_s = slip velocity
v_{tail} = gas tail velocity
V_w = wellbore volume
X_k = influx compressibility
X_m = mud compressibility
X_w = wellbore elasticity
z = gas compressibility factor

Greek letters

α = constant
λ = no-slip liquid holdup or input liquid content
ϕ = formation porosity
μ = gas viscosity
μ_f = formation fluid viscosity
ρ_g = density of gas
ρ_l = density of liquid
ρ_m = density of drilling fluid or mud
ρ_{ns} = two-phase no-slip density
$\partial p/\partial z$ = gradient pressure
$(\partial p/\partial z)_{elev}$ = gradient pressure due to elevation
$(\partial p/\partial z)_{fric}$ = gradient pressure due to friction

Subscripts

ini = initial
Δp = differential pressure
min = minimum
sc = standard conditions
stab = stabilized

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SUMMARY AND CONCLUSIONS

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Workshop Evaluation Form, Day 2

Session	Evaluation of Session				Comments
	Excellent	Good	OK	Not Needed	
Research Program Overview					
Improved Computer Model for Planning Dynamic Kill of Underground Blowouts					
Experimental Study of Bull-Heading Operations					
Experimental Study of Erosion Resistant Materials					
Use of Soil Borings Data for estimating Breakdown Pressure of Upper Marine Sediments					
API Task Group on Drillstring Safety Valves					
Well Design Requirements to Reduce the Vulnerability of Marine Structures to Cratering					
Reconfiguration of LSU No. 1 Test Well					
Control of Environmental Risks of Aging Offshore Pipelines - Proposal for Survey and Assessment of Available Technology					
Overall Program					

General Comments and Suggestions:

Suggested Top Research Priorities:

Please indicate your category below

- ☐ MMS Headquarters Representative
- ☐ MMS Pacific Region Representative
- ☐ MMS Gulf Coast Region Representative
- ☐ Research Industrial Sponsor
- ☐ Industry Representative